<Providing the Balance of Power>

PROVIDING THE
BALANCE
OF POWER

ONTARIO HYDRO'S PLAN

TO SERVE CUSTOMERS'

ELECTRICITY NEEDS

DEMAND/SUPPLY
PLAN REPORT

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PROVIDING THE BALANCE OF POWER

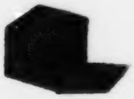
THIS "DEMAND/SUPPLY PLAN" REPORT IS ONE OF A SERIES OF DOCUMENTS ISSUED UNDER THE TITLE, "PROVIDING THE BALANCE OF POWER: ONTARIO HYDRO'S PLAN TO SERVE CUSTOMERS' ELECTRICITY NEEDS." THIS REPORT CONTAINS A COMPREHENSIVE DISCUSSION OF THE BACKGROUND TO, AND ELEMENTS OF, HYDRO'S PROPOSED PLAN TO MEET FUTURE NEEDS, AND THE ALTERNATIVES THAT WERE CONSIDERED. • A COMPANION DOCUMENT, "PLAN ANALYSIS," GIVES FURTHER TECHNICAL DETAILS AND SUPPORTING ANALYSES FOR THE PROPOSED AND ALTERNATIVE PLANS. ANOTHER DOCUMENT, "OVERVIEW," PRESENTS IN A MORE ABBREVIATED AND SOMEWHAT DIFFERENT FORM THE MAIN FEATURES OF THE PLAN, ITS ALTERNATIVES, AND THE CONSIDERATIONS THAT WENT INTO THEIR DEVELOPMENT. A FOURTH DOCUMENT, "ENVIRONMENTAL ANALYSIS," ANALYZES THE ENVIRONMENTAL IMPACT OF THE PROPOSED DEMAND/SUPPLY PLAN AND ITS ALTERNATIVES. • THESE DOCUMENTS WILL BE FILED WITH THE MINISTER OF THE ENVIRONMENT FOR A PUBLIC HEARING BEFORE THE ENVIRONMENTAL ASSESSMENT BOARD. PRIOR TO THAT HEARING, THESE DOCUMENTS WILL BE SUBJECT TO GOVERNMENT REVIEW, AND THEIR CONTENTS WILL BE THE FOCUS OF A PUBLIC INFORMATION PROGRAM TO BE CONDUCTED BY ONTARIO HYDRO.

THREE FORMS OF PLANNING ACTIVITIES

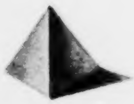
THE ELEMENTS OF ONTARIO HYDRO'S DEMAND/SUPPLY PLAN ARE SET FORTH IN THIS REPORT ON A CHAPTER-BY-CHAPTER BASIS. THE WAYS IN WHICH THE ELEMENTS INTERRELATE AND THEIR LOGICAL UNFOLDING ARE DEPICTED IN TWO FIGURES, FOUND IN CHAPTER 2 (FIGURE 2–1 AND FIGURE 2–2). IN ORDER TO UNDERSTAND THE BASIC PRINCIPLES BEHIND HYDRO'S PLANNING IN A MORE ELEMENTARY WAY, ONE CAN LOOK AT THE PLANNING PROCESS AS THREE TYPES OF PLANNING ACTIVITIES: ASSESSING NEEDS, DEFINING RESOURCES, AND MAKING PLANS. AS A VISUAL REMINDER OPENING EACH CHAPTER, A GRAPHIC FORM DEPICTS THE APPROPRIATE ACTIVITY FOR THAT CHAPTER.

THREE GEOMETRIC FORMS REPRESENTING THREE PLANNING ACTIVITIES

Assessing Needs: is depicted by a sphere. Electricity will be expected to provide a range of services over the next 25 years in all spheres of activity: home, work, recreation, and community activities. Hydro's planning assesses these needs and compares them to the resources available to meet them.

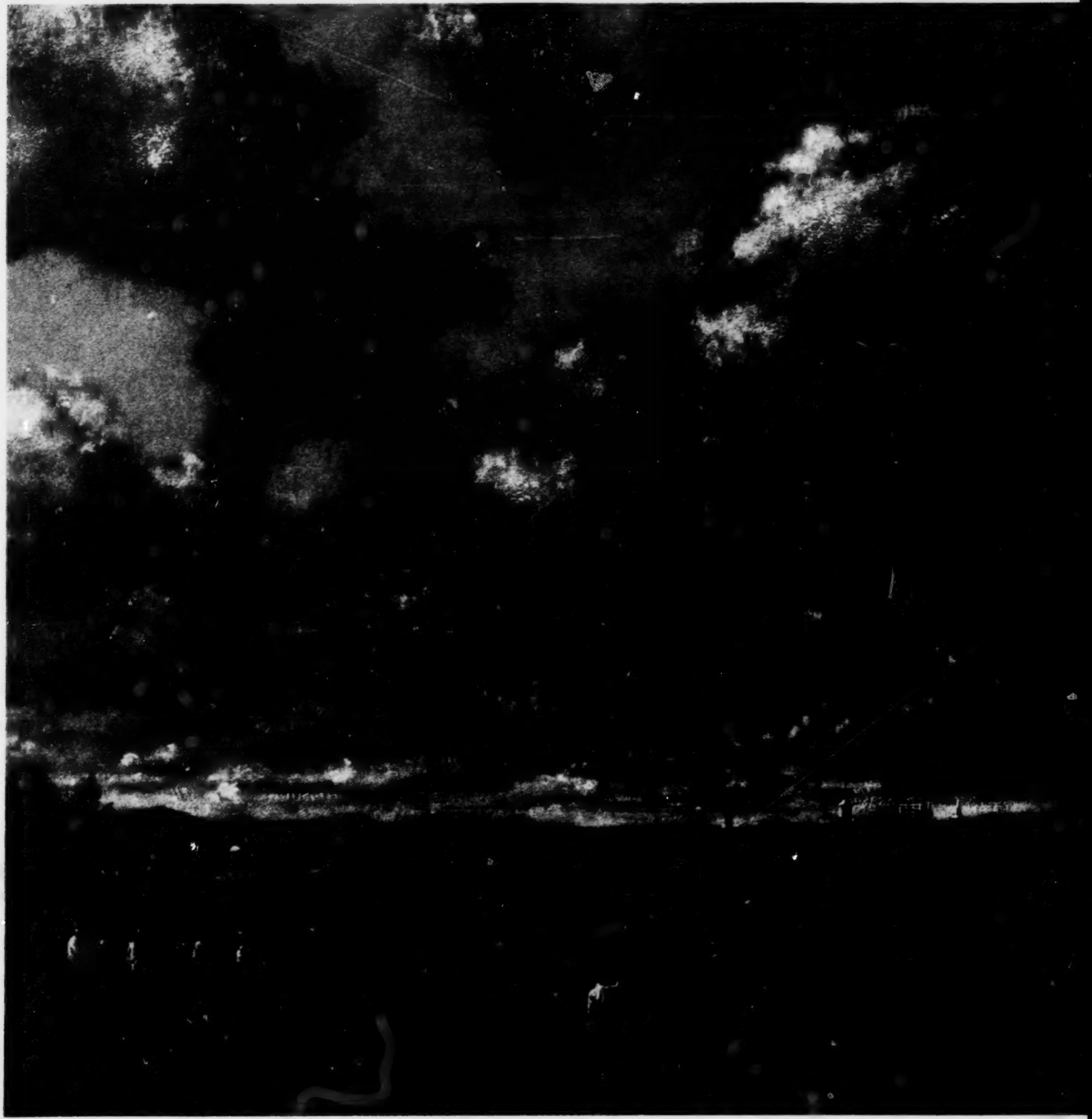


Defining Resources: is depicted by a cube. Resources means not just natural resources, but existing facilities and future options available to meet customer needs. Defining resources means identifying and evaluating options which are able to reduce the demand for electricity or to increase the supply to balance customer needs. This requires the development of techniques to compare and evaluate resources.



Making Plans: is depicted by a pyramid, which represents the balance between needs and resources. As needs grow and existing resources decline, plans must add the right amount of new resources to maintain the balance.

ASSESSING NEEDS



A growing Ontario means a growing need for more electricity services and programs to use it more efficiently over the next 25 years. Customer expectations also require that electricity be provided at low cost and with low environmental impacts.

There is some uncertainty about how fast Ontario's electricity needs will grow, but services that people use electricity for, like heating, cooling, lighting, motors, and appliances, are fundamental in today's society. Projecting the capability of Hydro's existing electrical system against future needs shows that plans to reduce growth in demand and provide additional supply are essential to maintain the quality of electrical service that the people of Ontario expect.

DEFINING RESOURCES

Generating stations age over time, and eventually have to be replaced. In 25 years over a quarter of today's facilities will be at the end of their service lives.

Additional electricity can be supplied from a number of sources - falling water, both from within Ontario and other provinces, coal, uranium, oil, and natural gas. Another resource to meet future needs is to reduce growing electricity needs by using electricity more efficiently and at off - peak periods, or to purchase power from others in the Province.

To meet customer expectations for reliable, low-cost, and environmentally sound electricity service, Hydro must identify, analyze, and evaluate current resources and future options.

MAKING PLANS

Existing resources are inadequate to meet the forecast range of future needs. In order to bring future needs and resources into balance, Hydro's integrated demand/supply plan combines demand-reducing options, like energy efficiency improvements and shifting electricity use from high peak periods, with options to increase supply – natural gas, hydraulic, and nuclear generation, and purchases from other provinces and non-utility generators.

Making plans involves combining options, testing and evaluating the results, selecting a proposed and alternative plans made up of both demand-reducing and supply options, and identifying the shorter term actions necessary to implement long-term plans.

EXECUTIVE SUMMARY
DEMAND/SUPPLY PLAN

1

The people of Ontario depend on electricity for services that are critical to their jobs, lifestyles and well being.

2

Ontario Hydro has the major responsibility for meeting these electricity needs, and has developed a plan which covers the next 25 years.

3

Ontario Hydro's plan reflects public and customer values including safety, environmental protection, reliability and low cost. The planning process provides opportunities for public discussion and review.

4

New initiatives must be taken now to meet growing demand and the requirement to replace aging generating stations. There is an increasing urgency to make decisions and implement the plans necessary to meet these needs.

5

Year over year growth in electricity energy demand has averaged between 7% and 3% for each decade of the last 30 years, but the growth in absolute terms has averaged about 600 megawatts per year for peak power and 3.5 TWh per year for energy over the same 30 years.

6

It is not possible to forecast the demand for electricity accurately over long periods because demand depends on the growth in the economy, the changing needs of society, changes in technology and the steps taken to use electricity more efficiently. Although load forecasts use historical information, they are not a simple extrapolation of the past.

7

To accommodate uncertainty, a bandwidth with an upper, median and lower forecast is used. Assuming no incentive programs to reduce demand, the median forecast is that the annual peak power demand will increase by an average of 2.2% per year during the period 1989 to 2014. The peak power demand is expected to increase at an annual rate of about 2.7% until the year 2000 and then fall to lower levels. The actual December 1988 primary peak power demand was 23.0 gigawatts and the firm load was 22.2 gigawatts.

8

As a result of its studies, Ontario Hydro believes that there is only a 10% probability that the actual demand will be greater than the upper forecast and a 10% probability that demand will be less than the lower forecast. Because of the difficulty in accurately forecasting demand over such a long period, the plan will permit all demand to be met which falls within the range between the upper and lower forecasts.

9

Ontario Hydro's system will have a total installed capacity of 32.5 gigawatts by January 1993 when Darlington is completed, with a load meeting capability of 26.3 GW. By January 2014, 8.7 gigawatts of capacity is expected to reach the end of its useful life. These retirements, which include 21 major generating units in five stations, will reduce the load meeting capability by 7.0 gigawatts.

10

The requirement for new demand and supply options necessitated by the retirement of facilities and the increased demand, ranges between 15.0 gigawatts and 26.2 gigawatts, depending upon whether the lower or upper forecast is used. The median forecast is that 21.3 gigawatts will be needed by January 2014, and 1.4 gigawatts will be needed by January 1994.

11

One of the important developments in Hydro's long-term planning to meet these needs is the integration of the customer or demand side of the electricity relationship. Demand management refers to measures taken by Ontario Hydro and municipal utilities to influence the amount and timing of customer electricity demand. Both demand and supply options are important components of the integrated demand/supply plan.

12

During the five-year period 1984 to 1989, Ontario Hydro conducted a Demand/Supply Options Study. All demand and supply options were reviewed that were relevant to meeting future electricity needs of Ontario. After extensive public participation, including reviews by the Select Committee on Energy of the Ontario legislature, the study resulted in the completion of a Demand/Supply Planning Strategy in March 1989.

13

The Demand/Supply Planning Strategy contains a set of principles, guidelines and priorities for use in the development of Ontario Hydro's Demand/Supply Plans. This plan is based upon that strategy.

14

The highest priority is given to an aggressive Demand Management Plan designed to reduce demand by increasing the efficiency in the utilization of electricity and by shifting the load away from peak periods of demand. It is estimated that the demand may be reduced by 3.0 gigawatts by January 1999, and by 5.4 gigawatts in January 2014, or about 25% of the additional requirement estimated for the median load forecast.

15

This ambitious plan is based on continuing cooperation with municipal utilities, customers, governments and the electrical industry to achieve successful delivery of the demand management programs.

16

High priority is given to the maintenance, upgrading, and refurbishment of the existing generation and transmission facilities so as to improve their performance, efficiency and reliability consistent with high standards of environmental protection.

17

The potential for obtaining supply from non-utility generators on an economic basis has been carefully examined. Ontario Hydro's objective is to obtain the maximum non-utility generated electricity which can be purchased at a cost not exceeding the cost to Ontario Hydro of providing the same quantity. Planned additions of NUG capacity are 1.6 gigawatts by 2000 year end, and 2.6 gigawatts by 2014 year end.

18

Ontario Hydro has given the economic development of its hydraulic resources a high priority, planning to develop nine new sites, redevelop three and extend the capacity of six. The planned hydraulic capacity addition is 1.1 gigawatts by January 1999 and 2.8 gigawatts by January 2014. In January 2014, the contribution to increasing load meeting capability is 2.2 gigawatts.

19

The planned demand management, non-utility generation and development of hydraulic resources aggregating 9.3 gigawatts is about 12 gigawatts short of the requirement in January 2014, as estimated for the median load forecast, and 15.7 gigawatts short for the upper load forecast.

20

Ontario Hydro has examined fourteen major supply options to satisfy the remaining requirement. The major options are purchases of electricity from neighbouring utilities, generation by fossil fuels and CANDU nuclear generation.

21

Ontario Hydro agreed in 1987 to purchase 0.2 gigawatts of electricity from Manitoba, commencing in 1998, for a term of five years, and has recently negotiated a purchase of 1.0 gigawatts for a term of 20 years, commencing in 2000. The levelized unit energy cost of these purchases is estimated to be 3.7 cents per kwh ($1989) which compares favourably with the cost to Ontario Hydro of generating the electricity itself.

22

Ontario Hydro has negotiated for some time to purchase up to 4 gigawatts of electricity from Hydro Quebec, but so far Hydro Quebec has quoted prices which are far in excess of the cost to Ontario Hydro of generating the electricity itself. These negotiations continue, but unless there is a major change in the proposed pricing, such a purchase will be uneconomic.

23

Recently the Premiers of Newfoundland, Quebec and Ontario discussed the development of 3.6 gigawatts of electricity at the Churchill River in Labrador, and a committee of the provincial utilities has been formed to consider the generation and transmission of this power to be shared by the three provinces. This discussion is at a very early stage, and would not lead to any new supply until the year 2000 at the earliest. All the proposed plans could be adjusted to accommodate this supply if it proved attractive.

24

From the fourteen major supply options, together with the high priority options, Ontario Hydro has selected three Demand/Supply Plans which satisfy its planning criteria which include cost, safety, reliability, diversity and the environment. Each Plan has the flexibility to accommodate changes in demand. They all permit the combination of options such as major generation projects with long lead times and options with short lead times capable of meeting unanticipated developments such as delays in the required approvals, changes in demand and changing fuel prices.

25

The environmental evaluations of options and plans include discussion of acid gas, greenhouse gases, radioactivity, and other relevant considerations.

26

The preferred choice, "the Proposed Plan", features the high priority options and uses CANDU nuclear generation to meet additional base load requirements, gas-fueled Combustion Turbine Units to meet peak load requirements, and existing fossil generation, modified by appropriate environmental controls, to meet intermediate load requirements. Under this plan to meet the median forecast to 2014, ten CANDU units would be installed at three stations, and thirty-two Combustion Turbine Units would be installed at four stations. All of the Combustion Turbine Units would be convertible to Combined Cycle or coal-fueled Integrated Gasification Combined Cycle as flexible fossil options.

27

A wide range of plans was studied including a plan with no new nuclear generation, and a plan with little new fossil generation. It was concluded these less diverse plans were not reasonable alternatives.

28

The acceptable Alternative Candidate Plans 22 (higher nuclear) and 24 (higher fossil) also feature maximum contributions from the high priority options. These Plans differ from the Proposed Plan in respect to the contributions of nuclear and fossil generation.

29

Figure ES-1 illustrates the contributions of the demand and supply options to meeting the customers' electricity needs at 5-year intervals to January 2014. This figure is for the Proposed Plan and median forecast.

It should be noted that in January 2014:

a) the required demand/supply is 21.3 gigawatts;

b) the planned demand reduction is 5.9 gigawatts;

c) the planned supply increase is 15.7 gigawatts, which includes 7.0 gigawatts for the replacement of the retired generation.

30

Figure ES-2 presents the capacity and energy contributions of the various types of supply used in the Proposed Plan to meet the customer demand after allowing for the demand reducing options. The existing supply (1993) is compared with the future supply in 2014 under the median forecast.

31

These figures show that the proposed plan uses a diverse mix of demand and supply options to meet Ontario's needs.

32

As the load forecast is very uncertain the Proposed Plan and the Alternative Plans provide for a wide range of possible demand for the

Figure ES-1 **Proposed Demand/Supply Plan 15 – Components**
Median Load Forecast (GW)

		Jan. 1989	Jan. 1994	Jan. 1999	Jan. 2004	Jan. 2009	Jan. 2014
	Basic Load Forecast (BLF)	23.2	26.9	30.2	34.5	37.0	39.8
Demand Reducing Options	Electrical Efficiency Improvements (EEI)	0.0	0.2	1.4	2.3	2.8	3.3
	Load Shifting (LS)	0.0	0.6	0.9	1.1	1.2	1.3
	Non-Utility Generation – Demand Displacement (NUG-DD)	0.0	0.3	0.4	0.4	0.4	0.5
	Capacity Interruptible Load (CIL)	0.7	0.6	0.7	0.7	0.8	0.9
Balance	Firm Load Forecast (FLF)	22.4	25.2	26.8	30.0	31.8	33.9
	Future System – Load Meeting Capability (FS-LMS)	23.2	25.8	27.1	30.0	31.8	34.2
***Supply Increasing Options**	Fossil (FOS)	0.0	0.0	0.0	1.1	2.4	4.3
	Nuclear (NU)	0.0	0.0	0.0	0.7	2.8	7.1
	Utility Purchase (UP)	0.0	0.0	0.2	0.8	0.8	0.8
	Hydraulic (HY)	0.0	0.02	0.9	1.5	1.8	2.2
	Purchase Non-Utility Generation (P-NUG)	0.0	0.3	0.6	0.9	1.1	1.2
	Existing System – Load Meeting Capability (ES-LMC)	23.2	25.5	25.5	25.0	22.8	18.5
	*Retirements	0.0	0.0	0.0	0.6	2.3	7.0
Meeting Requirements	Required Demand/Supply (R-D/S)	0.0	1.4	4.7	9.5	14.1	21.3
	Demand Reductions in the Plans	0.7	1.7	3.4	4.5	5.2	5.9
	*Supply Increase in the Plans	0.0	0.3	1.7	4.9	9.0	15.7
	Plans Total	0.7	2.0	5.0	9.4	14.1	21.6

**All supply options expressed in Load Meeting Capability*

Figure ES 2. Supply Contribution – Capacity and Energy
Proposed Plan 15 – Median Load Forecast

Supply Capacity					Supply Energy			
Generation	**Jan. 1993**		**Jan. 2014**		**1993**		**2014**	
Type	**GW**	**%**	**GW**	**%**	**TWh**	**%**	**TWh**	**%**
Hydraulic	6.5	19.8	9.4	22.1	35.7	23.5	40.8	19.1
NUG Purchase	0.3	0.9	1.5	3.5	2.9	1.9	10.3	4.8
Manitoba Purchase	0.0	0.0	1.0	2.3	0.0	0.0	7.0	3.3
Nuclear	14.2	43.3	20.1	47.2	93.2	61.4	143.0	66.9
Fossil	11.8	36.0	10.6	24.9	20.0	13.2	12.5	5.9
Totals	32.8	100.0	42.6	100.0	151.8	100.0	213.6	100.0

year 2014, ranging from that required by the lower forecast to that required by the upper forecast:

upper 44.7 GW }
median 39.8 GW } bandwidth = 11.2 GW
lower 33.5 GW }

33

Timely approvals are requested to permit the upper load forecast to be met. The actual commitments to build facilities will be made on the basis of actual load growth experience. The Approvals to meet the upper load forecast are required so that Ontario Hydro will have the flexibility to adjust if load growth is higher than the median forecast.

34

The approvals requested are for certain of the electricity supply facilities included in the Candidate Plans, and pertain to:

a) the requirement and rationale for transmission in Ontario to incorporate purchases from Manitoba; and

b) the requirement and rationale for generation facilities and associated radial transmission facilities adequate to meet the requirement under the upper load forecast.

Such approvals if granted will avoid a duplication of effort when the necessary applications are made for the approval of specific generation and transmission projects.

Chapter 1

Introduction

The purpose of the Demand/Supply Plan is to identify actions needed to serve the future electricity needs of the people of Ontario over the next 25 years and beyond.

Hydro's planning, reflecting customer values, gives priority to maintaining existing facilities and, where economic, to demand management, non-utility generation and hydraulic development.

Purpose of the Plan
1
Environmental Assessment
3
Public Review
4
Integrated Planning
4
Planning Strategy
7
Approval
7
Scope
8
The Demand/Supply Plan
9

Chapter 2

A Planning Overview

The end product of the planning process is a Demand/Supply Plan which integrates demand reducing and supply options to meet increasing customer demand for electricity.

Continuous Nature of Planning
1
Main Planning Features
6
Structure of the Report
6

Chapter 3

Basic Load Forecast

Chapter 3 discusses what customer requirements for electricity service would be without Hydro's financial incentives to influence the level and timing of electricity demands on Ontario Hydro.

There is a range of uncertainty about how rapid the growth will be. Hydro's forecast range of growth is from 1.7 to 2.7 per cent a year.

Basic Load Forecast Defined
1
History of Electricity Use
5
Factors in Forecasting
8
The Long-Term Load Forecast
13
Forecasting Methodology
18
Customer Use Patterns
25

Chapter 4

The Existing System

Providing electricity service involves reliability and the environment, as well as low cost. Ontario Hydro currently relies on hydraulic (25%), fossil fuels (25%), and nuclear (50%) for its electrical energy.

In 25 years, over a quarter of today's generating facilities will be at the end of their service lives, thus reducing ability of the existing system to meet customer needs.

Capacity
3
Energy
4
Utilization
6
Environment
10
Service Life
12
Reliability Reserve
17
Load Meeting Capability
21

Chapter 5

Requirement for Demand/Supply Options

Requirements for New Demand/Supply options compares the forecast electricity peak power and energy demand with the capability of the existing electricity system. Under the median forecast, new options are required by 1993, and by 2014, over 21,000 MW of demand-reducing and supply-increasing options will be required.

Peak Requirements
1
Maintaining Reliability
3
Energy Requirements
5
Timely Decisions
7

Chapter 6

Costing Concepts and Avoided Costs

Costing concepts are described which allow Hydro to compare options with different characteristics and to compare plans whose options are implemented at different times, operate differently, and last for different periods of time.

Avoided cost methodology helps determine whether high priority projects like demand management and non-utility generation are economic.

General Costing Concepts
3
Total Customer Costs
4
Uncertainty - Expected Costs
11
Social and Environmental Costs
12
Avoided Costs
15

Chapter 7

[illegible]

Two elements of demand management are energy efficiency improvements, which reduce the amount of electricity needed to provide a given service, and load shifting, which reduces peak demand by shifting consumption from high-use to low-use periods.

Capacity Interruptible Loads, where customers contract to cut back their use during peak periods, are also part of demand management.

The Demand Management programs will contribute about 5000 MW to meeting future needs.

Concepts of Managing Demand
2

Environmental Factors
6

Efficiency Potential
9

Load Shifting Opportunities
17

Capacity Interruptible Loads
20

Demand Management Plan
21

Chapter 8

[illegible]

Ontario Hydro gives high priority to opportunities for customers, independent producers, and other utilities to meet future needs by producing their own electricity.

The contribution from non-utility generation (NUG) can be in the form of reducing or eliminating the customer's own electricity needs or in selling power to Hydro. The NUG Plan will add 2,500 MW of new capacity by 2014.

Concepts of Non-utility Generation
2

Factors Influencing Potential
3

Attainable Non-Utility Generation
5

Environmental Considerations
8

Non-utility Generation Plan
10

Chapter 9

The Primary and Firm Load Forecasts

The Primary Load Forecast is derived by subtracting the expected future impact of reductions in demand resulting from electrical efficiency improvements, load shifting, and non-utility generation from the Basic Load Forecast.

The Firm Load Forecast takes into account reductions in Hydro's capacity requirement resulting from Capacity Interruptible Loads.

Primary Load Forecast Defined
1

Firm Load Forecast
4

Chapter 10

Rehabilitation

Rehabilitation is designed to get maximum economic use from existing facilities. Its purpose is to replace worn out, obsolete, or inefficient major components of existing facilities.

It ensures continuing safety, reliability, economy, and environmental acceptability of these facilities to the end of their service lives.

Concepts
1
Hydraulic Rehabilitation
3
Fossil Rehabilitation
5
Nuclear Rehabilitation
8
Mothballed Stations
10
Redevelopment
13
Rehabilitation Plan
13

Chapter 11

Requirement for New Supply

To reliably meet future customer needs, Hydro must have a supply capability that includes a reliability reserve to accommodate stations out of service for planned and forced outages. The future system capacity requirement is equal to the Firm Load Forecast plus reliability reserve.

The required capacity from the new supply options is 19,250 MW by 2014. That supply comes from hydraulic, nuclear, fossil and purchases from non-utility generators or neighbouring utilities.

Capacity Requirement
1
Energy Requirement
1

Chapter 12

The Hydraulic Plan

While a renewable resource, hydraulic opportunities are not inexhaustible. Undeveloped hydraulic resources have a reasonably large theoretical potential, but environmental, ecnomic, and technical factors limit how much falling water can actually be used to generate electricity.

The Hydraulic Plan calls for development of 18 hydraulic sites which contribute 2,935 MW of capacity and 6.0 TWh per year of energy.

Characteristics of Hydraulic
1
Hydraulic Potential
3
Economics of Hydraulic
7
Hydraulic Plan
8

Chapter 13

Requirement for Major Supply

The requirement for major supply is equal to the total required new supply less the planned supply from purchases of non-utility generation and hydraulic generation.

Under the median forecast, by 2014, the requirement for major new supply is 15,000 MW of capacity.

Capacity Requirement
1
Energy Requirement
1
Uncertainty and Planning
5

Chapter 14

Major Supply Options

Options evaluated for development into plans include Quebec and Manitoba purchases, CANDU 3 and 881 MW CANDU nuclear units, conventional coal and coal gasification stations, natural gas and oil-fired combustion turbine units, and combined cycle gas plants.

Siting and transmission aspects associated with the options are also considered in this chapter.

Review of Options
1
Criteria for Evaluation
5
Identification of Suitable Options
7
Purchase Options
7
Fossil and Nuclear Options
11
Rationale for Selections for Plans
28
Siting Considerations
35
Transmission Considerations
40

Chapter 15

Major Supply Plans

Criteria used to select a proposed plan include reliability, safety, environmental performance, cost, technical soundness, flexibility and social considerations.

The Plan selected uses nuclear and natural gas technologies to meet major supply needs. Two other plans were also found acceptable – one using a higher proportion of nuclear, and the other using coal in place of one of the proposed nuclear plants.

Criteria and Considerations
1
Cases Formulated
8
Capacity and Energy Contribution
28
Siting and Illustrative Transmission
33
Comparison of Cases
37
Selecting Candidate Plans
70
Selection of Proposed Plan
71

Chapter 16

Avoided Cost Determination

Hydro's avoided cost is the supply costs which are avoided when any demand or supply option is substituted for an equivalent part of a demand/supply plan.

Avoided cost varies with factors such as time of delivery, load growth, and the candidate plans. The avoided cost of candidate demand/supply plans is used to determine the avoided cost used in the development of the Demand Management, Non-utility Generation, and Hydraulic Plans

Simplified Method
1
Full Simulation System Incremental Costs
2
Incremental Energy Cost
4
Incremental Power Cost
8
Avoided Cost Sensitivity
12
Examples
14
Avoided Cost Feedback
17

Chapter 17

Demand/Supply Plans

Demand/Supply plans integrate plans for rehabilitation, demand management, non-utility generation, and hydraulic generation with major supply plans.

Each of these integrated sets of plans is called a Demand/Supply Plan.

One of these Demand/Supply Plans is identified as the Proposed Plan, and two are identified as acceptable alternatives.

Common Components
1
Variable Components
5
Demand/Supply Plans
6
Rationale for Proposed Plan
15

Chapter 18

Action Plans

The Action Plans focus on the actions which must be taken to implement the Demand/Supply Plans. Each Demand/Supply Plan has actions associated with it, some of which require approvals.

Chapter 19

Approvals

Each plan contains a number of components, and the approvals being requested in this application are precisely identified. This is done for the Proposed Demand/Supply Plan and for each Alternative Demand/Supply Plan.

1 INTRODUCTION

The people of Ontario depend on electricity for services that are critical to their jobs, lifestyles, and well-being. Ontario Hydro has a major responsibility for meeting those electricity needs.

Part of that responsibility is planning for what customers will need and expect well into the future.

Providing reliable power has been Hydro's obligation for decades, but there is more to electricity service than making sure that power is available on demand. Needs evolve over time. Customers change, as do their concerns and priorities. Customers view many factors as important to Hydro's planning, including what they pay for services, what technologies are used, what environmental impacts there will be, how Hydro can help in using electricity more efficiently, and how people can help Hydro plan and provide for the future.

These customer values must be factored into long-range utility planning, and so must other developments in society – such as a growing population and economy, the development of new technologies, and the changing prices of fuels and other commodities.

Growing and changing customer needs are one impetus for planning. Another is that Hydro's ability to meet those needs with the current system will decline as generating stations age and eventually need replacing.

Today – facing growing use of electricity and the approaching retirement of older generating stations – there is an increasingly urgent need to make decisions and implement the plans necessary to meet future electricity requirements.

Those requirements are substantial. By 2014 new options to reduce growth in demand and increase supply are needed in amounts which, in total, are approximately equal to today's entire system demand. Options are needed now for three basic reasons:

- To provide continuing reliable electricity service to customers – by ensuring that the generation capacity available is adequate (after allowing for demand reducing options);
- To maintain low electricity costs to customers – by ensuring that low cost energy demand and supply options are developed; and
- To meet environmental objectives by meeting regulations and standards and by taking a leadership role in environmental protection.

Without timely decisions on new demand and supply options, it will not be possible to achieve all of these objectives.

Hydro's planning cannot focus only on immediate problems and circumstances. It must respond to longer term expectations – for two key reasons:

- First, because of the long service lives of generating stations and the associated major commitments to future fuel resources. Decisions

Ontario's farming community depends on a reliable source of electricity.

Select Committee on Energy

The Select Committee On Energy of the Ontario Legislature noted in 1989 "The supply of electricity is vital to the functioning of our modern society. Many of the advanced technological processes and equipment which we have come to rely upon depend on a reliable and economical supply of electricity. The Committee has also learned that the continued supply of electricity is a complex matter with a broad range of alternatives and diverse environmental, social, economic, and public policy implications."

Hydro's Customers

Ontario Hydro's customers are its 860,000 rural retail customers, 105 direct industrial customers, and the 316 municipal utilities. Because these utilities themselves sell power to 2.5 million homes and businesses throughout Ontario, most end users of electricity are not strictly speaking Ontario Hydro's customers. However, when the term "customer" is used in this report, it will refer to all electricity users in the province.

Apart from traditional service issues like reliability and cost, customers are also members of the public, and have a relationship with Hydro that is based on broader issues like the environment, safety and other social impacts.

taken within the next few years will have major effects in Ontario for much of the next century.

- Second, because of the long lead times – 10 years or more – to bring new facilities and programs into operation, some of the decisions taken over the next few years will not deliver results until 10 or 15 years from now.

Meeting long-term expectations must be carried out in the face of high uncertainty with respect to forecast growth. Uncertainty, which is necessarily a part of any forecast of electricity growth, is recognized in Hydro's planning in the bandwidth[†] of possible load growths – upper, median, and lower.

Changing patterns of electricity use must also be factored into planning. The history of year-over-year growth in electricity demand[†] has ranged from about 7% to 3% over the past three decades, but the growth in absolute terms has been a steady 600 megawatts a year.

Yet forecasting can never be a simple extrapolation of past trends. It must recognize uncertainty. Factors like population and the economy, the development of new technologies, and the changing prices of fuels and other commoditites all affect future need. Hydro plans on the basis of a bandwidth of possible growth – upper, median, and lower.

Contributing to the quality of life of today's and tomorrow's generation.

If load grows near the median of the range, new options must be put in place commencing in the early 1990s. If load follows the upper forecast,[†] the need for new supply/demand options is particularly urgent.

Environmental Assessment

Ontario's environmental assessment legislation is designed to encourage good planning and informed decision making. The Environmental Assessment Act sets out a variety of requirements to assist in achieving these objectives. In general terms, they include consideration of alternatives, and the identification and evaluation of the effects, advantages and disadvantages of the proposal submitted for approval and its alternatives. Under the Act, specific matters – those for which approval is requested and required – are identified as the undertaking.

The undertaking, as described in this environmental assessment document, is made up of specific Demand/Supply Plan components, and constitutes a Program in respect of activities associated with meeting future electricity requirements. The approvals requested are set out in Chapter 19. The Program represents only a part of the results of the integrated demand/supply planning which led to the

[†] terms marked with this symbol are found in the glossary.

identification of Candidate Demand/Supply Plans. Many of the components of the Plan, such as demand management,† do not require Environmental Assessment Act approvals.

Public Review

The environmental assessment process provides formal opportunities for organizations and individuals to present their views to the hearing panel making the decisions on the Program. But apart from the hearing, Hydro will also be providing opportunities throughout Ontario for the public to meet with Hydro representatives – to help in the public understanding of the planning process, and the Proposed Demand/Supply Plan.

While the plan put forward in this document represents Hydro's judgment on how best to meet Ontario's future electricity requirements, it also has the flexibility to accommodate different conclusions on many of the trade-offs which are necessarily part of electricity planning for Ontario.

So the views expressed during the public information program will be important – those views will be carefully considered, and will be reflected in Hydro's presentations at the hearing. The hearing itself will contribute to the public debate and discussion of planning issues, and Hydro's position will be responsive to that debate.

Focus on Integrated Planning

One of the important developments in Hydro's planning process is the integration into long-term planning of the customer or demand side of the electricity relationship.

Demand side activity is by no means new to Ontario Hydro. For many years, Hydro has worked with customers to improve a variety of electricity uses – an example being improving the insulation on water heaters. What is significant about the role of the demand side today is its role in long-term planning.

In the past, utility planning was mostly concerned with meeting service needs through increasing supply. In the earlier years of this century, the planning priority was to develop new technologies for generating and transmitting power. Small systems were linked together into larger ones to gain economies of scale, increasing reliability and lowering cost to electricity users. The emphasis was on the expansion and the integration of the province-wide supply grid.

In the last 30 years, year–over–year growth in electrical demand has ranged from about 7% to 3%, but growth in absolute terms has been a steady 600 MW a year. In response to growing customer needs and a changing society, Ontario Hydro has put in place a variety of large generating stations which have served customers well in providing reliable service. Forecast future growth again demands that Hydro respond to a changing and growing Ontario. But Hydro's response will reflect new kinds of priorities.

Influencing customer use, demand management, is now a top priority in Ontario Hydro planning. Demand management has been integrated into planning so that Hydro can evaluate demand and supply options on an equivalent basis, and determine the most appropriate ways to reduce growth in demand while meeting the requirements for increased supply.

Non-utility generation (NUG)† also has an important role to play in meeting future energy needs. Non-utility generation is electrical generation owned and operated by producers in Ontario other than Ontario Hydro. Non-utility generation adds diversity to traditional

Integrated Planning: New Factors

Preparation of the Demand/Supply Plan has integrated a variety of factors, including:

- **Public consultation on planning principles and options**
- **Demand Management**
- **Non-Utility Generation**
- **Retirement of aging generating stations**

The Development of the Demand/Supply Planning Strategy

1984

Ontario Hydro was in a surplus situation. However, Ontario Hydro foresaw the need for new demand/supply options before the end of the century. This provided an opportunity to review and reconsider all the options.

Hydro undertakes a comprehensive study of all demand and supply options available to generate or save electricity. This includes options which have only specialized or limited commercial applications.

1985–86

Hydro initiates public consultation to determine what customers and the public value as important about electricity service, what concerns they have, and what preferences, priorities and options they would like to see Hydro follow in planning.

This consultation process included legislative select committees, public interest groups, government ministries, customer attitude surveys, and community representatives in many centres across Ontario.

1986

Select Committee on Energy of the Ontario Legislature holds a public hearing to discuss Hydro's planning options.

1987

Hydro develops a Draft Demand/Supply Planning Strategy – a set of principles, priorities, and guidelines to be used in the development and updating of Demand/Supply Plans.

This strategy was based upon the options study carried out during 1984 and 1985, the public input received, and a detailed study of 15 representative plans covering the following broad approaches:

- Extremes with "all demand" options and "all supply" options
- Mixed plans with both demand and supply options
- Distributed plans using smaller supply and demand options
- Impact of no new nuclear generation
- High purchases and fossil generation
- Impact of delaying work on supply options
- Price-induced demand reductions

The study of the representative plans includes the following:

- Financial impacts
- Environmental impacts
- Social and community impacts
- Sensitivity and risk analysis
- Provincial economic impact assessment
- Discussion of resource diversity
- Transmission aspects

1988

The Ontario Nuclear Safety Review, conducted by Dr. F. Kenneth Hare, concludes that the Ontario Hydro reactors are being operated safely and that the risk of accidents serious enough to affect the public adversely can never be zero, but is very remote.

The Government of Ontario begins a review process of Hydro's draft planning strategy which includes ministerial reviews, a specially constituted Electricity Planning Technical Advisory Panel review, a Select Committee on Energy review and the Ontario Nuclear Cost Inquiry.

1989

Hydro's draft Strategy is revised based on recommendations received, and is approved by Ontario Hydro's Board of Directors in March 1989.

Avoided costs are the supply costs avoided when any demand or supply option is substituted for an equivalent part of a demand/supply plan.

electricity supply resources and promotes the recycling of waste products as fuel. Because of the relatively small scale of many NUGs, they can be built fairly quickly and can be adapted more easily to local conditions. They also encourage private sector producers to share development and financing risks with Hydro.

The primary method used by Hydro to establish the economic value of demand management and non-utility generation is the avoided cost[†] concept. By calculating Ontario Hydro's avoided costs, the costs and benefits of various demand management and non-utility generation projects can be compared with supply options.

"Avoided costs" are the supply costs avoided when any demand or supply option is substituted for an equivalent part of a demand/supply plan.

A major factor which must be integrated into today's planning is the expected retirement of a large amount of existing generating capacity. For the first time in Ontario, a significant reduction in the load meeting capability of Hydro's existing system must be accommodated in planning.

During the 25-year plan period, all or part of five generating stations (totalling 8.7 GW of capacity) are due to be retired.

Another important feature is the integration of public views and inputs into Hydro's planning process. In order to ensure that its planning reflects the public's priorities and values, Hydro sought their views on electricity options and planning priorities.

Throughout this report reference is made to concerns about maintaining reliable power, protecting the environment, ensuring public safety and keeping electricity costs low. Consultation and feedback from customers and the public have shown these values to be by far the most important planning priorities for Hydro.

Priorities in Planning

The Demand/Supply Planning Strategy contains five basic thrusts:

- **Ontario Hydro will give top priority to demand management to reduce load growth through electricity use efficiency and load shifting. Demand management options that contribute to low customer cost of electrical service will be aggressively pursued. The cooperation of municipal utilities, customers, governments and the electrical industry will be essential for the successful delivery of demand management programs.**
- **Ontario Hydro will give a high priority to the maintenance, upgrading and refurbishment of the existing generation and transmission facilities such as to improve their performance, efficiency, and reliability consistent with high standards of environmental protection.**
- **Ontario Hydro will give a high priority to encouraging non-utility generation to provide a part of the need for new resources. Preference will be given to renewable resources such as small hydro and wood waste. Also fossil generation which employs high efficiency cogeneration will be preferred over conventional technology.**
- **Ontario Hydro will give a high priority to the orderly development of the remaining economic hydraulic potential, recognizing that this is a renewable but limited resource.**
- **Ontario Hydro will keep open the options for major new supply facilities to meet growth and the need to replace old plants and thus ensure a reliable electricity service into the next century. The major supply options are CANDU nuclear, fossil and firm purchases from Manitoba and Quebec.**

The Demand/Supply Planning Strategy best meets the future electricity needs of Ontario and will give the flexibility to cope with an uncertain future.

Priorities, Strategy, Plan

In March of 1989 Ontario Hydro completed development of the Demand/Supply Planning Strategy. This strategy was a culmination of a five-year planning process involving the study and testing of options, public input on values, and the development of a strategy to assist in the identification, evaluation and selection of options and plans. The Demand/Supply Planning Strategy (DSPS) is included in Appendix A. The DSPS is a set of principles, priorities and guidelines which provide the basis for planning – setting out the rationale for a consistent approach in making judgments and decisions about such plan elements as costing principles, resource preferences, and evaluation criteria. The Proposed Plan is based on the Demand/Supply Planning Strategy.

In preparing the strategy, the focus was on the development of planning principles and priorities, electrical service values, and various supply and demand options. For the Demand/Supply Plan, the focus has shifted to the preparation, review and approval of definitive plans and proposals.

The work to develop a long-term demand/supply plan focussed on identifying a 25-year proposed plan – and an associated shorter term action plan – which best reflect the planning strategy. During the process, a large number of different plans – called cases – were studied. Each of these considered a different combination of options. Evaluations led to three alternative plans, known as Candidate Plans.

The Strategy sets out criteria for developing and assessing alternative plans. All alternative plans considered in the evaluation had to meet environmental and reliability requirements and standards. Further analysis also evaluated each case on criteria such as resource preferences and provincial economic impact.

An environmental analysis of alternative plans was also undertaken. Natural and social environmental criteria were identified. The environmental effects of the demand management, non-utility generation and hydraulic plans, and of the major supply plans were identified and analyzed along with potential for mitigation of adverse environmental effects. The results of this analysis are presented in the reference report, Demand/Supply Plan, Environmental Analysis Report.

In developing the Demand/Supply Plans, Hydro gives priority to:

- maintaining and improving the existing system
- economic demand management
- economic non-utility generation
- remaining economic hydraulic generation

These all take priority over developing additional major supply plans and are a common element in all the plans. This approach is consistent with customer and public feedback to Hydro, and with the advice of the Select Committee.

Approval Requested

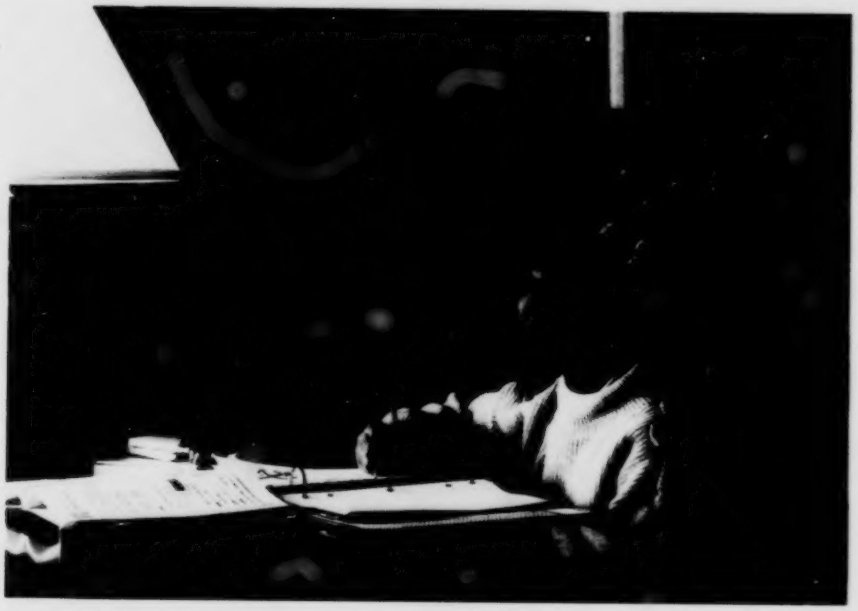
Ontario Hydro has developed a Demand/Supply Plan for the provision of electricity service in Ontario. The Plan proposes various options to be committed over the next 25 years for service to the people of Ontario over much of the next century. This report explains the rationale for the proposed Demand/Supply Plan, including the rationale for those plan components recommended for approval under Ontario's Environmental Assessment Act.

Alternative plans with different advantages and disadvantages were evaluated and compared in arriving at this recommendation. The overall Demand/Supply Plan includes major commitments to electricity-reducing options; to electricity generation to be owned and operated by independent producers (non-utility generation); to purchases from outside the province; to rehabilitation of existing Ontario Hydro facilities; and to the orderly development of hydraulic resources. The Plan also proposes the addition of fossil and nuclear generation facilities.

Many of the components of the Plan do not require Environmental Assessment approval. The Program Approval requested in this application relates only to certain components of the Plan, including the following:

- **the requirement and rationale for:**
  - **transmission facilities to incorporate electricity purchased from Manitoba;**
  - **eleven stations in the Hydraulic Plan;**
  - **new fossil generation; and**
  - **new nuclear generation**
- **the requirement and rationale for combustion turbine units on existing sites, if required to meet electricity demand.**
- **the requirement and rationale for radial transmission to connect the above generation to the Ontario Hydro transmission system.**

For the formal description of the approval requested, reference should be made to Chapter 19. Subsequent assessment of individual projects will focus on ensuring that those projects are located and implemented in an environmentally acceptable manner. The project assessments will not duplicate nor reconsider the planning issues determined by this application.



Electricity is so much part of our lives that we rarely think of where it comes from.

Scope

The Demand/Supply Plan addresses a range of demand and supply options which require different time periods to implement, and which have long-lasting implications for the province.

The Plan identifies the need for additional demand and supply commitments over a 25-year time horizon – responding to the long lead times needed for implementation. Options do not make a contribution to meeting customers' electricity needs until they are approved and implemented.

The Plan covers a wide range of supply options. It includes the purchase of electricity from Manitoba, and from Ontario sources other than Ontario Hydro (non-utility generation), as well as generating stations owned and operated by Hydro.

The Plan also covers a wide range of demand-reducing options, including incentives to customers to use electricity more efficiently or to shift use to off-peak times. Options are available for all types of customers – residential, commercial, and industrial.

The Plan also includes those hydraulic projects for which the planning and approvals process is underway – Little Jackfish, Niagara, the Mattagami Complex, and two smaller sites.

Although the Plan includes evaluation of the radial transmission required to connect generation into the electricity system, it does not address future needs for the inter-area transmission required to transfer energy between various areas in the province. These are being studied, and separate inter-area transmission plans are being developed for public review.

As options are implemented over the planning period, Hydro's facilities continue to age. Some of Hydro's hydraulic stations will exceed 100 years of age during the planning period. Similarly, the coal stations built in the 1950s and '60s will reach the end of their useful lives. Some of the nuclear units are scheduled for retirement within the 25-year timeframe. The Plan provides for replacement of retiring plants as well as serving growth in customer needs.

The implication for technologies having such long service lives is that decisions taken today have impacts for many generations. Hydro customers today are being served reliably and at low cost by past investments.

For the immediate future, the only options which are reasonable to consider are those based on today's proven technologies. At the same time it is necessary to retain sufficient flexibility to take advantage of technological advances and other opportunities as they become available.

While low cost and reliability are important in meeting customer expectations, so are environmental considerations. All options must address electricity needs in a responsible way, and environmental considerations are a key component in developing and evaluating plans.

The Demand/Supply Plan

This Demand/Supply Plan represents a milestone for Hydro and its customers. It is the first plan to integrate demand management and non-utility generation in a comprehensive and systematic way. It is the first plan in over a decade to propose the approval of major new supply options. It is the first plan to use explicitly a publicly reviewed strategy as a basis for planning. It is the first plan that must address the retirement of a large amount of generating facilities as well as growth in customer demand.

The Plan calls for an integrated approach to meeting Ontario customer electricity needs. An integrated approach is necessary to achieve an appropriate balance in planning – and achieving balance is an important goal of the Demand/Supply Plan.

Planning aims for balance in a quantitative sense – balancing estimates of future customer needs for electricity with the resources to meet them.

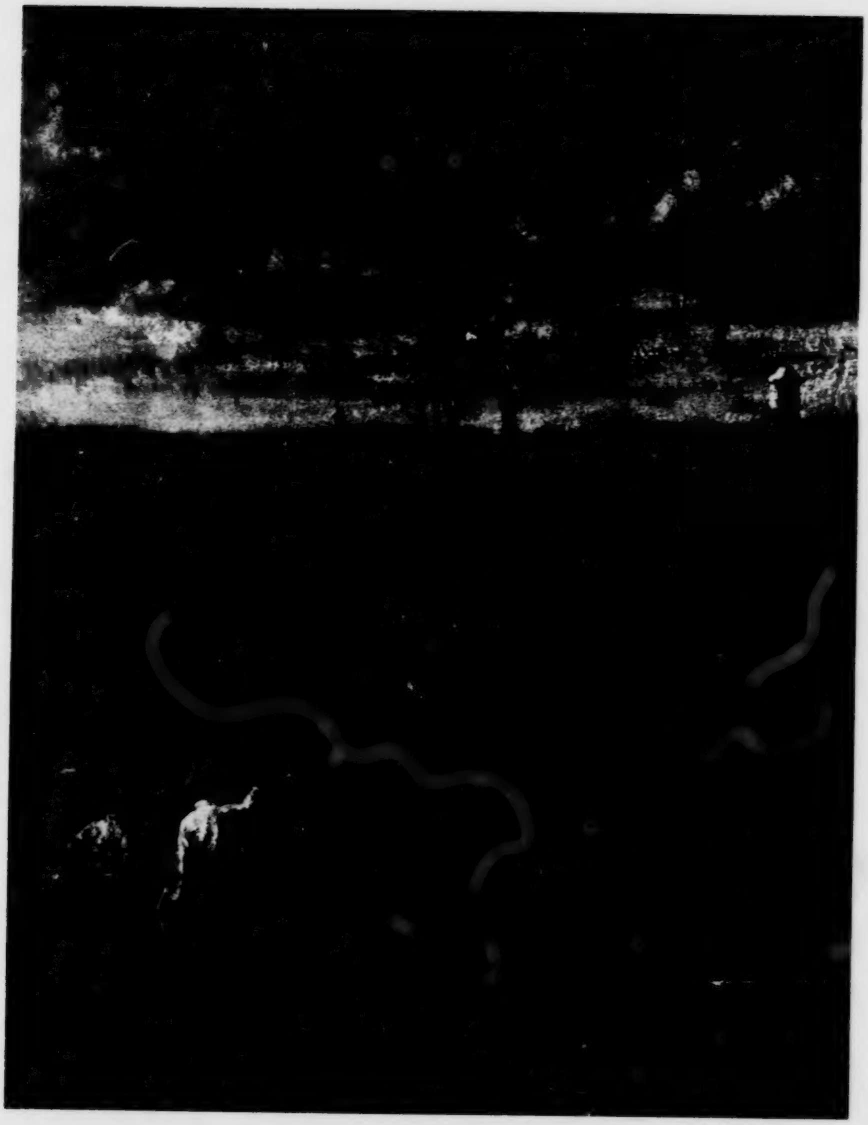
Planning also aims for balance in a qualitative sense – balancing customer values like reliability, a clean environment, and low cost.

The Demand/Supply Plan provides balance in both senses. It draws together an appropriate mix of demand and supply options, and ensures that the needs for the next 25 years can be met.

The Plan:

- maximizes the use of the existing system;
- pursues all economic demand management and non-utility generation opportunities;
- develops economic hydraulic sites;
- incorporates out-of-province purchases; and,
- meets the balance of future requirements with new fossil and nuclear generating capacity.

Ontario Hydro recommends the proposed Demand/Supply Plan to the people of Ontario, confident that it provides appropriate balance in electric power planning.



2 PLANNING OVERVIEW AND REPORT STRUCTURE

In addition to a brief discussion of characteristics and appropriate principles for planning, this chapter provides a guide to the balance of the document by outlining the content of each of the next 17 chapters.

In turn, those chapters provide the main facts, guiding principles, evaluation criteria, comparisons and judgments that led Hydro to its recommendations. More detailed data and analysis can be found in the supporting reports referenced at the back of the document.

Continuous Nature of Planning

The end product of the planning process is a Demand/Supply Plan, which comprises a set of plans addressing various options for meeting customer electricity needs. These options include demand management, non-utility generation, hydraulic, rehabilitation, and major supply additions.

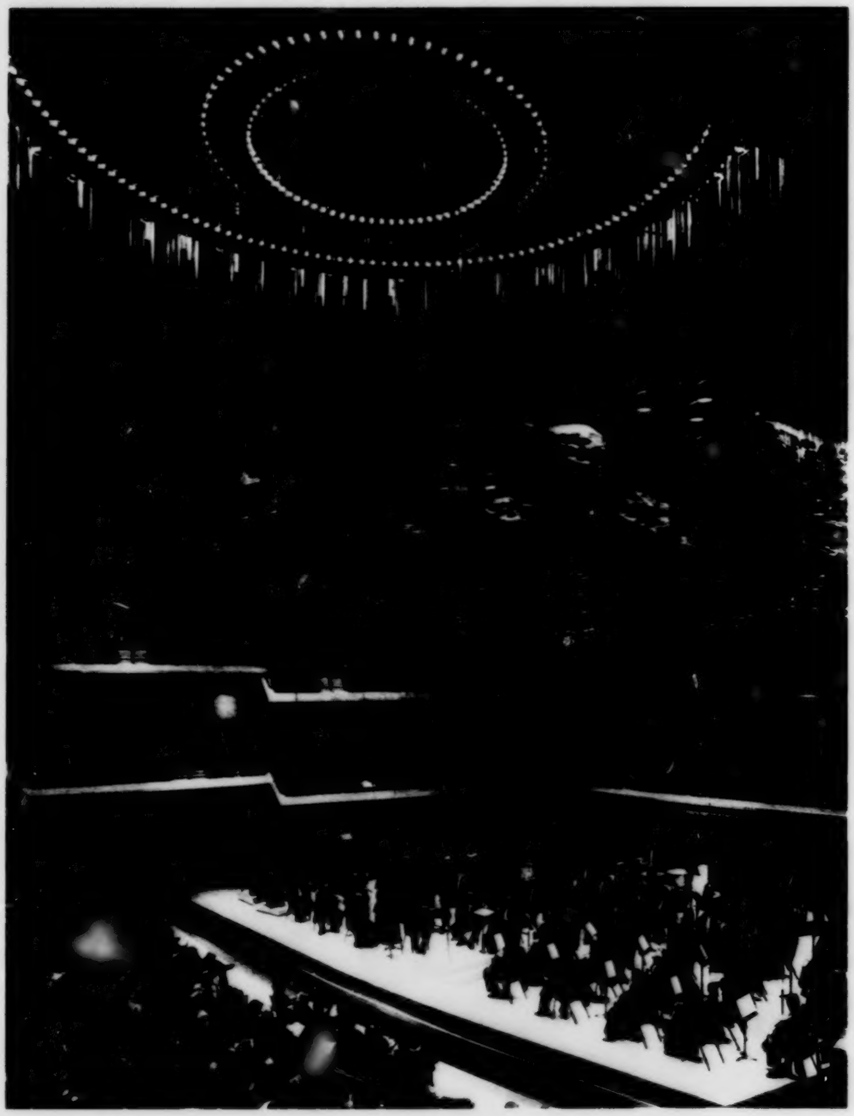
The general approach to the demand/supply planning process considers the following four blocks of activities.

- First, the requirement for additional demand/supply options to meet the future customer electricity needs of Ontario is determined.
- Second, the feasible demand and supply options are identified to meet these needs, and their planning characteristics are determined. Planning characteristics include:
  - availability
  - cost
  - reliability
  - environmental impacts
  - economic impacts
- Third, plans are developed and analyzed. Each plan contains a selected set of the demand/supply options as one way of meeting the future needs.
- Fourth, the most effective plan is proposed and acceptable alternatives are identified.

The chapters in the report are designed to set out the various elements of planning in a sequence which shows their logical linkages, recognizing that planning itself is an ongoing process.

Each year the data base on actual customer loads† is updated and new forecasts are developed for economic and load growth and other factors. Similarly, the options are updated considering cost experience, changing technology and new environmental requirements. The plans are then adjusted to take into account the updated forecasts and options. This process of updating, reviewing and adjusting plans is a continuous process.

While recognizing that adjustments will be necessary from time to time, long-term planning must give a firm direction for future actions. The Demand/Supply Plan meets this objective.



Electricity plays a role in our enjoyment of cultural activities.

Using the Planning Guide Figure 2–1

The planning guide Figure 2–1 illustrates in a simplified way the essential steps in the demand/supply planning process. The structure of this plan report is based on this guide. At the beginning of each chapter, the guide is reproduced to highlight the applicable planning component.

Figure 2-1 **Demand/Supply Plan – Report Structure**

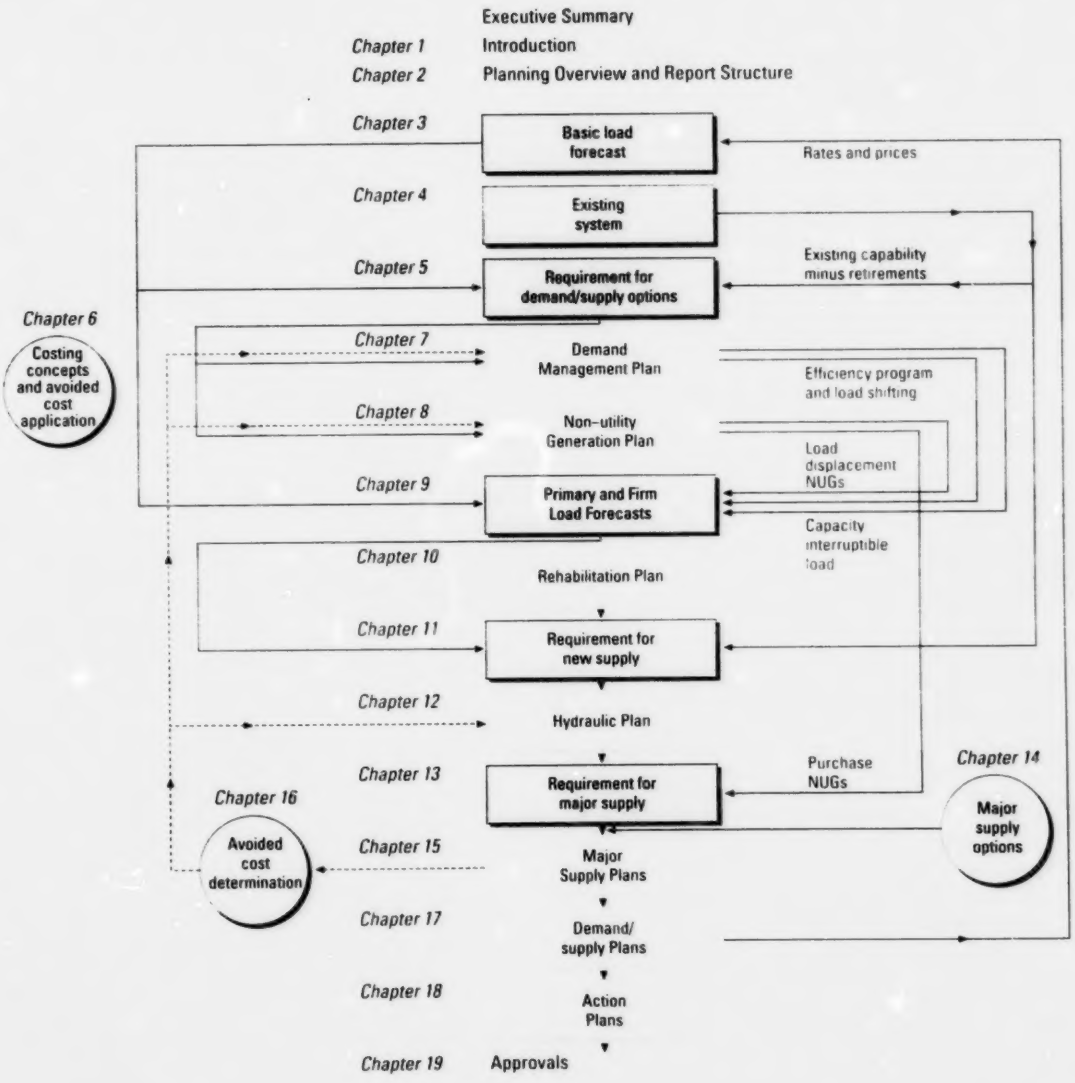
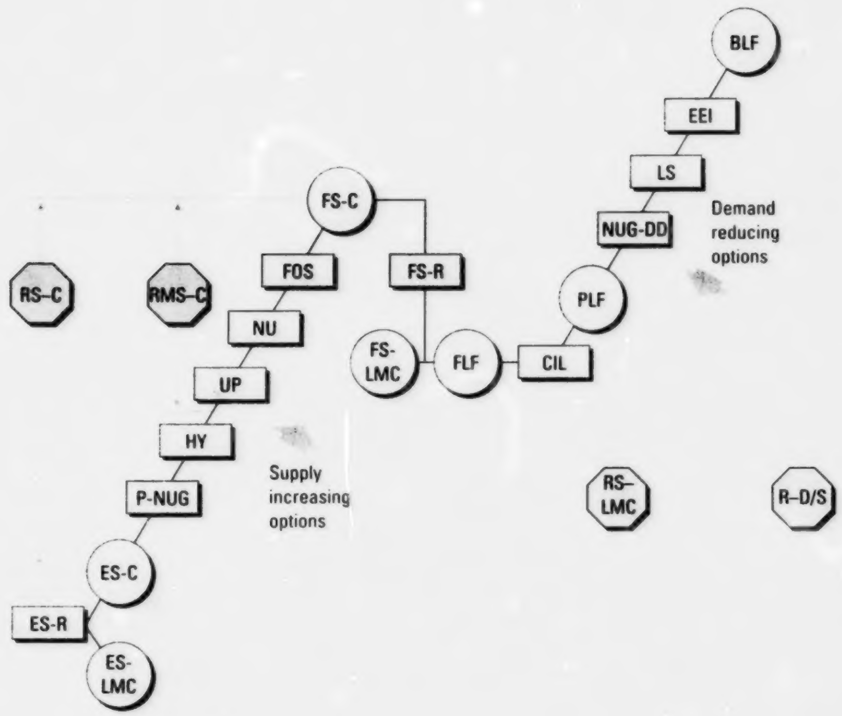

Executive Summary
Chapter 1
Introduction
Chapter 2
Planning Overview and Report Structure
Chapter 3
Basic load forecast
Rates and prices
Chapter 4
Existing system
Chapter 5
Requirement for demand/supply options
Existing capability minus retirements
Chapter 6
Costing concepts and avoided cost application
Chapter 7
Demand Management Plan
Efficiency program and load shifting
Chapter 8
Non-utility Generation Plan
Load displacement NUGs
Chapter 9
Primary and Firm Load Forecasts
Capacity interruptible load
Chapter 10
Rehabilitation Plan
Chapter 11
Requirement for new supply
Chapter 12
Hydraulic Plan
Chapter 13
Requirement for major supply
Purchase NUGs
Chapter 14
Major supply options
Chapter 16
Avoided cost determination
Chapter 15
Major Supply Plans
Chapter 17
Demand/supply Plans
Chapter 18
Action Plans
Chapter 19
Approvals

Figure 2–2 **Demand/Supply – Terms and Interrelationships**



Legend

C	Capacity
LMC	Load meeting capability
R	Reserve
ES	Existing system
P-NUG	Purchase NUG
HY	Hydraulic
UP	Utility purchase
NU	Nuclear
FOS	Fossil
FS	Future system
FS-R	Future system reserve
EEI	Electrical efficiency improvement
LS	Load shifting
NUG-DD	NUG demand displacement
CIL	Capacity interruptible load
FLF	Firm load forecast
PLF	Primary load forecast
BLF	Basic load forecast

Requirements

RS-C	Required supply capacity
RMS-C	Required major supply capacity
RS-LMC	Required supply load meeting capability
R-D/S	Required demand/supply

Demand/Supply Balance Diagram

Figure 2–2 lays out the various planning components and shows how they achieve a balance by reducing demand and increasing supply.

The following are the steps in this "balance diagram" moving first from right to left (reducing demand), then from left to right (increasing supply).

THE DEMAND SIDE

The Starting Point

BLF (Basic Load Forecast): The Basic Load Forecast is the forecast of peak power and energy demand that Ontario Hydro would have to meet without financial incentives to influence the amount and timing of demand on Hydro's system.

Demand Reducing Options

EEI (Electrical Efficiency Improvements): Hydro has incentive programs in place to encourage customers to adopt higher efficiency electrical equipment and to use electrical equipment more efficiently. The net effect is to reduce the peak power and energy demand.

LS (Load Shifting): Load shifting reduces the peak power demand by shifting some electricity demand from periods of high use to periods of low use.

NUG-DD (Non-Utility Generation, Demand Displacement): This refers to non-utility generation which supplies electricity to meet the producer's own needs. Although it involves additional generation of electricity, it has the effect of reducing the peak power and energy demand on Hydro's system.

PLF (Primary Load Forecast): This refers to the forecast obtained by subtracting EEI, LS, and

NUG-DD from the Basic Load Forecast. The Primary Load Forecast is the forecast of peak power and energy which Ontario Hydro would normally generate or purchase in order to meet customer demands.

CIL (Capacity Interruptible Load): Some customers contract to reduce their power demand at the request of Hydro when the peak demand on Hydro's system begins to exceed supply. Capacity Interruptible Load (CIL) is the peak power reduction expected to occur when the contracted loads are interrupted.

FLF (Firm Load Forecast): This is derived by subtracting the Capacity Interruptible Load from the Primary Load Forecast. The Firm Load Forecast is used for planning capacity requirements.

Demand Reductions Summary

The Firm Load Forecast used for planning supply is equal to the Basic Load Forecast minus the four demand reducing options – EEI, LS, NUG-DD, and CIL.

BALANCE POINT

FS-LMC (Future System Load Meeting Capability): For any year, balance exists if the load meeting capability of the future system is equal to the Firm Load Forecast for that year.

FS-R (Future System Reserve): To maintain reliable customer supply when stations are out of service for planned and forced outages, and in face of uncertain load growth, there is a need for additional generating capacity called Future System Reserve.

FS-C (Future System Capacity): The required Future System Capacity is equal to the Future System Load Meeting Capability plus the Future System Reserve.

THE SUPPLY SIDE

The Existing System

ES-LMC (Existing System Load Meeting Capability): This is the projected firm load that the existing system can meet for any year in the plan period.

ES-R (Existing System – Reserve): To maintain reliable customer supply when stations are out of service for planned and forced outages, and in face of uncertain load growth, there is a need for additional generating capacity called Existing System Reserve.

ES-C (Existing System – Capacity): This is the installed capacity of the existing system. It is equal to the Existing System Load Meeting Capability plus the Existing System Reserve.

Supply Increasing Options

P-NUG (Purchase Non-Utility Generation): The power produced from economic non-utility generators is part of Hydro's plan to meet future electricity needs.

HY (Hydraulic Generation): Development of the remaining economic hydraulic generation in the province will increase future supply.

UP (Utility Purchase): Purchases from out-of-province utilities are used to increase supply when economic compared to Hydro's own generation options.

NU (Nuclear): CANDU nuclear is a major supply increasing option.

FOS (Fossil): Fossil generation is a major supply increasing option using fuels such as coal, gas and oil.

Supply Increasing Summary

The Future System Capacity is equal to the Existing System Capacity plus the five supply increasing options P-NUG, HY, UP, NU and FOS.

Balancing Demand and Supply

A "balance diagram" is illustrated in Figure 2–2. The diagram illustrates the following:

- The components of the Demand/Supply Plan.
- The options which reduce electricity demand.
- The options which increase the supply.

The diagram shows how the supply and demand are balanced.

REQUIREMENTS

R-D/S (Required Demand/Supply): For any future year the Required Demand/Supply (R-D/S) is equal to the difference between the Basic Load Forecast (BLF) and the Existing System Load Meeting Capability (ES-LMC). The R-D/S is to be met by new demand and supply options.

RS-LMC (Required Supply Load Meeting Capability): For any future year the Required Supply Load Meeting Capability (RS-LMC) is equal to the difference between the Future System Load Meeting Capability (FS-LMC) and the Existing System Load Meeting Capability (ES-LMC).

RS-C (Required Supply Capacity): For any future year the Required Supply Capacity (RS-C) is equal to the difference between the Future System Capacity (FS-C) and the Existing System Capacity (ES-C). The RS-C is to be met with new supply options.

RMS-C (Required Major Supply Capacity): For any future year, the Required Major Supply Capacity (RMS-C) is equal to the Future System Capacity (FS-C) minus the Existing System Capacity (ES-C), the Purchase Non-Utility Generation (P-NUG) capacity and the Hydraulic (HY) capacity. The RMS-C is to be met by new major supply options.

Main Planning Features

There are six critical features of Ontario Hydro's demand/supply planning. These are:

1. That it is integrated demand/supply planning in that both the supply of additional electricity and the implementation of demand measures to reduce demand through better use are expected to provide important contributions in meeting future requirements.
2. That the evaluation criteria used in planning are comprehensive. Options have been assessed and plans developed on the basis of low cost, and high flexibility, as well as their ability to meet technical and reliability standards. Environmental and social impacts have been considered in the assessment of both options and plans. Detailed local environment and siting considerations will be the subject of project environmental assessments.
3. That there are clear planning priorities for the selection of options. Priorities are to be given to demand management, non-utility generation, and hydraulic generation, and to maintaining and improving the existing system. After developing the plans for these priority options, the major supply plan is developed to meet the remaining requirements.
4. That developing plans provide flexibility to accommodate uncertainty in the load forecast, in forecasts for demand management and non-utility generation, and uncertainty in forecasting the future cost and performance of potential supply options.
5. That a long time-frame for planning is necessary, given the 10 or more years needed for bringing into service major supply options, and the long lasting impacts (up to 90 years or more) of planning decisions.
6. That considerable public input went into the development of the Demand/Supply Planning Strategy, and there will be further opportunities for public input during the review of this report, and during the project-specific environmental assessments.

Structure of Report

The report structure is shown in Figure 2–1. The content of each chapter is outlined below and the relationship of that chapter within the report is shown on the report structure diagram.

CHAPTER 3: BASIC LOAD FORECAST discusses customer electricity demand – for both peak power† and energy† – in the absence of certain Ontario Hydro programs designed to reduce that demand. Forecast electricity sales growth is the first major reason why new demand/supply options are required.

This chapter discusses the major factors which influence the forecast such as population, economic growth, and changes in use of electricity. The methods used to develop the forecast are described. This chapter also describes the bandwidth† forecasts for both peak power and energy which reflect the uncertainty in the load forecast. Ontario Hydro develops plans which are flexible to accommodate this uncertainty.

CHAPTER 4: THE EXISTING SYSTEM discusses the ability of the existing electricity system to meet peak power and energy demand. The capacity of the existing system is expected to be reduced by more than 25% in the next 25 years as generating units reach the end of their useful life. This is the second major reason why new demand/supply options are required.

CHAPTER 5: REQUIREMENT FOR NEW DEMAND/SUPPLY OPTIONS compares the forecast electricity peak power and energy demand (discussed in Chapter 3) with the projected peak load and energy-meeting capability[†] of the existing electricity system (discussed in Chapter 4).

For example, in the year 2014, the median forecast for peak power demand is 39.8 GW and the peak load-meeting capability of the existing system is 18.5 GW. Therefore, the requirement for demand/supply options is 21.3 GW. These comparisons identify the need over time for additional demand/supply options.

Similarly, in the year 2014 under the median forecast, required energy is 234 terawatt hours (TWh), while the energy capability of existing generation is 136 TWh. Therefore, there is an energy requirement to provide 98 TWh.

This chapter also discusses the effect of load growth uncertainty on the requirements for new options.

CHAPTER 6: COSTING CONCEPTS AND AVOIDED COSTS. Chapter 1 indicated that, when economic, demand management, non-utility generation, and hydraulic generation in Ontario are given high priority. The avoided cost concept is a method which helps determine whether or not these options are economic. Careful application of this avoided cost concept helps ensure fair comparison among options – and that total customer costs are kept low.

This chapter also discusses other costing concepts used for plan and option evaluations. Techniques based on these concepts allow Hydro to compare options with different characteristics, for example, high fueling costs versus high capital costs. They also allow Hydro to compare plans with different options that are implemented at different times, operate differently, and last for different periods of time.

The chapter concludes with a presentation of avoided costs for typical applications based upon the Proposed Plan.

CHAPTER 7: THE DEMAND MANAGEMENT PLAN. With the appropriate mechanism for defining what are economic demand and supply options described in Chapter 6, Hydro can proceed to its plans for demand management. Chapter 7 describes the demand management plan. Two key elements of demand management are electrical efficiency improvements[†] (EEIs), measures which reduce the amount of electricity needed to provide a given service, and load shifting[†] (LS), which reduces peak demand by shifting customer consumption of electricity from times of high use to low use periods. Capacity interruptible loads[†] are another component of demand management.

Pursuing economic demand management has been given top priority. This chapter describes the concepts, opportunities, and programs being implemented by Ontario Hydro. It also describes the methods used to develop this plan. This includes a discussion of market sectors, market segments, end-use, barriers, and incentives.

In the year 2000, Ontario Hydro plans to achieve a load reduction of 3.0 GW (approaching the capacity of the Darlington Nuclear Station) and 10 TWh, rising to 4.8 GW and 17 TWh by 2014.

CHAPTER 8: THE NON-UTILITY GENERATION (NUG) PLAN. In this chapter the opportunities for non-utility generation (NUG), a high-priority option for Ontario Hydro, are discussed, as are the critical factors

Working with Ducks Unlimited, Hydro preserved this 50-hectare wetland behind the Lennox Generating Station.

A hygrometer is installed to check acid rain deposits. Careful monitoring is essential to track our progress in reducing sulphur and nitrogen oxide emissions.

influencing the development of that potential.

The chapter outlines Hydro's plans for non-utility generation, and the steps being taken to ensure maximum economic generation is achieved.

The NUG Plan is for 1.6 GW of new installation by the end of 2000 rising to 2.6 GW by the end of 2014.

Non-utility generation has two categories – load displacement† and purchases. Load-displacement NUGs displace load from Ontario Hydro when the customers meet all or part of their own needs.

Purchase NUGs are purchases of electricity by Ontario Hydro from NUG developers.

Chapter 9: The Primary and Firm Load Forecast. With the Demand Management and Non-Utility Generation plans established, the demand remaining to be met is examined. Chapter 9 introduces the Primary Load Forecast and Firm Load Forecast.

The Primary Load Forecast is the forecast of the electric power and electric energy which Ontario Hydro must generate or purchase to meet the electricity demand of its customers in Ontario. It is derived by subtracting the expected future impact of electrical efficiency improvements (EEIs), load shifting (LS), and demand displacement NUGS from the Basic Load Forecast, for both peak power and energy.

The Firm Load Forecast is the forecast that is used for the planning of supply. The Firm Load Forecast is the forecast of the electric power and electric energy which Ontario Hydro must generate or purchase to meet all customer electricity demand of Ontario Hydro, except capacity interruptible loads (CIL).

The Firm Load Forecast is derived by subtracting from the Primary Load Forecast the estimated coincident power associated with the Capacity Interruptible Loads at the time of the annual peak.

The Firm Load Forecast for peak power in the median case is 27.4 GW in January 2000 and 33.9 GW in January 2014. The Firm Load Forecast for energy is the same as the Primary Load Forecast – 171 TWh of energy under the median forecast in 2000 and 214 TWh in 2014.

CHAPTER 10: REHABILITATION PLAN. Another strategic direction given high priority in the DSPS was the commitment to make the maximum economic use of existing facilities by improving or maintaining their performance. Chapter 10 deals with rehabilitation. Rehabilitation is a set of activities to replace worn out, obsolete, or inefficient major components of existing facilities.

It ensures continuing safety, reliability, economy, and environmental acceptability of these facilities to the end of their service lives.

The rehabilitation plan describes hydraulic rehabilitations, major overhauls and pollution controls on coal stations to help reduce acid gas emissions, and the retubing of some nuclear units to ensure safe, reliable operation for their 40-year expected service lives. The projection of the capability of the committed system discussed in Chapter 4 includes the effect of the Rehabilitation Plan.

CHAPTER 11: REQUIREMENT FOR NEW SUPPLY. This chapter derives the requirement for new supply options. The Firm Load Forecast, which must be reliably met with supply, is discussed in Chapter 9. The future system is required to have a load meeting capability equal to the Firm Load Forecast.

To reliably meet the demand, it is necessary to provide a reliability reserve† to accommodate generation out of service for planned and forced outages and other factors. The future system requirement is equal to the Firm Load Forecast plus reserve.

Finally, the peak power requirements for new supply options are equal to the future system capacity requirement minus the existing system capacity. In the case of energy, the requirements for new supply options are equal to the Firm Load Forecast for energy minus the energy meeting capability of the existing system.

For example, in the median case, the required future system capacity in 2014 is 42.1 GW. The existing system capacity in 2014 is 22.9 GW, and the required capacity from the new supply Options is 19.1 GW. That supply comes from hydraulic, nuclear, fossil and purchases from non-utility generators or neighbouring utilities. For energy requirements, the firm energy forecast is 214 TWh, the energy meeting capability of the existing system is 136 TWh, and the required energy supply is 78 TWh.

CHAPTER 12: THE HYDRAULIC PLAN describes Ontario Hydro's plan for hydraulic generation. Hydraulic development is given priority over major supply options.

Remaining undeveloped hydraulic resources have a reasonably large theoretical potential, but environmental, economic, and technical factors limit how much falling water can actually

To protect the Osprey and avoid power interruptions the nests are carefully relocated.

Warm water discharged from a power plant is used successfully to breed fish commercially.

be used to generate electricity. While a renewable resource, hydraulic opportunities are limited.

The chapter describes a hydraulic plan for an orderly development of 18 hydraulic sites which contribute 2.8 GW of capacity and 6 TWh a year of energy by the end of 2014. Investigation and environmental assessment is already under way for eight sites.

CHAPTER 13: REQUIREMENT FOR MAJOR SUPPLY. This chapter derives the requirements for new major supply options – fossil, and nuclear stations and purchases from neighbouring utilities.

The requirement for major supply is equal to the total required new supply less the planned supply from purchase NUGs and hydraulic generation.

For example, for the median case by 2014, the required major new supply capacity is 14.9 GW. For the lower growth case the forecast major new supply requirements by 2014 is 9.3 GW, and in the upper growth case, it is 19.3 GW. For energy, the requirements are 62 TWh for the median, 34 TWh for the lower, and 82 TWh for the upper forecast. Hydro's plans not only recognize the median forecast requirement, but allow sufficient flexibility to respond to upper or lower growth.

CHAPTER 14: MAJOR SUPPLY OPTIONS identifies the most suitable major supply options for the time period under consideration, together with their key characteristics.

Major purchases of hydraulic generation from Hydro Quebec and Manitoba are described. Ten most suitable fossil options are selected for study. These options include coal, oil, and natural gas fuels, available conversion processes, and the currently available environmental control concepts. The CANDU nuclear options considered are the Darlington type 881 MW units and the CANDU 3.

The characteristics of the options are matched with system requirements, and seven are selected for development of the major supply plan described in Chapter 15.

Siting and transmission aspects are also considered in this chaper.

CHAPTER 15: MAJOR SUPPLY PLAN describes the primary and secondary planning criteria and other considerations used for the formulation and evaluation of plans. The Major Supply Plan includes utility purchases and fossil and nuclear generation.

Plans are formulated using combinations of selected options identified in Chapter 14. The plans are evaluated and one plan is selected as the Proposed Plan. Two other acceptable Candidate Plans are also selected.

CHAPTER 16: AVOIDED COST DETERMINATION shows how avoided costs are calculated, and provides examples of how the avoided cost varies with factors such as time of delivery, load growth, and the Candidate Plans.

This chapter discusses the feedback from the plan avoided cost to the development of the Demand Management Plan, Non-utility Generation Plan and Hydraulic Plan.

CHAPTER 17: DEMAND/SUPPLY PLANS integrates plans for demand management, non-utility generation, and hydraulic generation with the Major Supply Plan alternatives.

Three Candidiate Demand/Supply Plans are developed and one is identified as the proposed Demand/Supply Plan. The chapter provides an overview of the characteristics of each Plan.

CHAPTER 18: ACTION PLANS focuses on the actions which must be taken to implement the Candidiate Demand/Supply Plans.

CHAPTER 19: APPROVALS identifies the approvals being requested in this application. This is done in relation to the Proposed Demand/Supply Plan and the two alternative Candidate Demand/Supply Plans.

APPENDICES. Appendix A is the Demand/Supply Planning Strategy. Appendix B is a list of reference documents. Appendix C is a glossary of terms used in this report.

→ **Chapter 3** Basic Load Forecast

Chapter 4 The Existing System

Chapter 5 Requirement for Demand/Supply Options

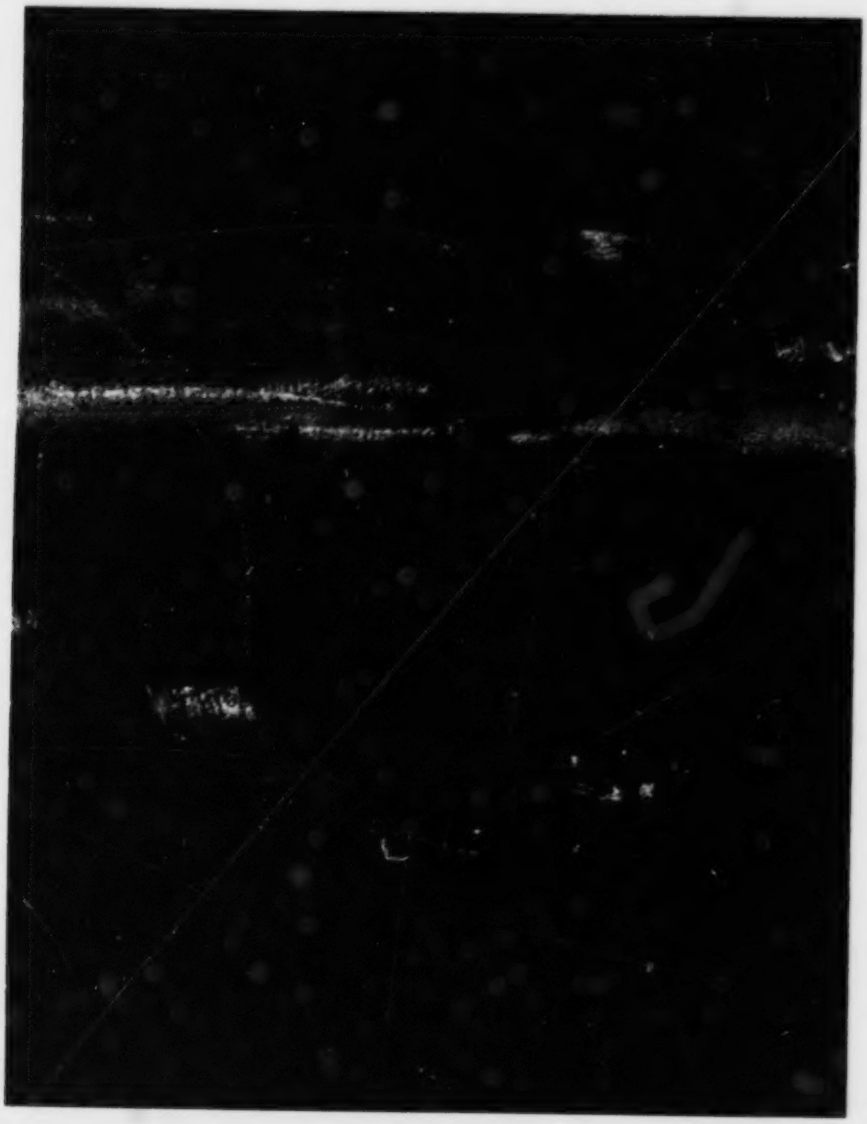
Chapter 6 Costing Concepts and Avoided Costs

Chapter 7 The Demand Management Plan

Chapter 8 The Non-utility Generation Plan

Chapter 9 The Primary and Firm Load Forecasts

Chapter 10 Rehabilitation Plan



3 BASIC LOAD FORECAST

Many services needed by the people of Ontario are provided by electricity. Residential customers need to wash clothes, refrigerate food, cook meals and maintain comfortable temperatures in their homes.

The choice of energy form to provide these and many other energy services demanded around the house is made in the course of the broader buying decisions for appliances and equipment. In some instances, electricity may be the only option. In others, convenience, cost, and efficiency may determine the choice of energy form, e.g., oil, gas and electricity.

In addition to the choice of energy form, buying decisions have impacts on how energy is going to be utilized. Residential customers' demand for electricity is the result of numerous decisions about energy choice, efficiency of use, and rate of utilization to meet their energy service requirements.

Similarly, commercial customers make many energy decisions, including how to light, heat and cool their premises. Industrial customers strive to optimize energy use as one of the inputs to their production processes.

Electricity demand, at any point in time, is the result of the decisions made by all customers in the course of meeting their energy service needs.

Forecasting demand, while it uses analytical tools, is essentially about people's lifestyles, values, and activities in society. Forecasting must also recognize technology and its development and evolution.

Forecasting the demand for electric energy is an attempt to predict future customer demand for the services that electricity provides, and how much electricity it takes to provide them. The size and nature of the economy, the prices of competing energy forms and the evolving cost and performance of energy-using equipment are key elements in the forecasting process. So are the impacts of government policy and Hydro activities which could alter the energy choices that customers make.

Given that forecasting demand is an attempt to predict people's behaviour, uncertainty is formally recognized as an inherent part of the process. This uncertainty is recognized by expressing the forecast as a bandwidth, rather than a single line forecast.

The Demand/Supply Plan is based upon the December 1988 Load Forecast. During 1989, a new Load Forecast was developed which is higher than the December 1988 forecast. This change illustrates the need to have a flexible plan which reflects the uncertainty in the Load Forecast.

The Basic Load Forecast† – The Starting Point

Long-term planning starts with a long-term forecast of demand. This chapter presents the long-term forecast of the demand for elec-

In critical applications a reliable supply means more than convenience and comfort.

tricity by Ontario Hydro's customers. The Basic Load Forecast given in this chapter is the forecast of what the demand for electricity would be without Hydro's financial incentives to influence the level and timing of electricity demands on Ontario Hydro.

What the Basic Load Forecast Includes

The Basic Load Forecast takes account of energy efficiency improvements that are driven by normal market forces. Residential, commercial, and industrial customers may choose to obtain the same level of energy service that they have been getting by, for example, improving electrical efficiency or by switching energy forms. These actions may decrease or increase their electricity demand. Hydro has a history of providing information about efficient technology to its customers and this service speeds up the adoption of more efficient uses of energy, including electricity.

Electrical efficiency improvements will occur as a result of continuing technical advances and the normal replacement of equipment that has reached the end of its useful life with more efficient current technology. Improvements will also occur as a result of the general programs mounted by Hydro and government agencies to provide the information consumers require to take advantage of efficiency improvement technologies.

The Basic Load Forecast takes account of the load displacement non-utility generation that is driven by normal market forces. Some customers, particularly industrial customers, reduce their costs by producing both process steam and electricity from one fuel (cogeneration†) or by developing their own independent generation of electricity. This reduces the demand for electricity that Hydro will have to provide.

The Basic Load Forecast also includes the effects of efficiency standards established by governments and their agencies.

What the Basic Load Forecast Does Not Include

The Basic Load Forecast does not include the future impacts of incentive-driven programs for demand managment and load displacement non-utility generation. As part of its demand/supply planning, Hydro is committed to a series of programs to motivate its customers to reduce their demand for electricity below what it otherwise would have been. Hydro is offering financial incentives to achieve this objective.

The expected net impact of Hydro's financial incentives to reduce the load on its system through demand management and load displacement non-utility generation is discussed in the Primary† and Firm† Load Forecasts (described in Chapter 9).

Forecasting for the Long Term

The forecast takes a long-term trend point of view. To put future electricity demand for the next 25 years in context, this report reviews trends and patterns over the past 25 years. The load forecast is not an extrapolation of the past. Rather, it is derived through the use of an econometric model (top-down approach) and an end use model (bottom-up approach) as described later in this chapter.

The long-term load growth forecast is likely to be lower than a simple extrapolation of the growth in the last six years which consisted largely of recovery from the 1982 recession. Further, should load growth rates fall in the next few years as a result of an economic slowdown, this should not be expected to affect the long-term load growth forecast. Long-term

Key Electricity Terms: Power and Energy

Electrical energy is a quantity term, like kilometres. It describes an amount of electricity supplied or used. The unit of measurement used in this report is the Watt-hour.

Electrical power is a rate term, like kilometres per hour. It describes the rate at which electrical energy is supplied or used. The unit of measurement is the Watt.

In the context of power system planning, the amounts used are much greater than several watts or watt-hours. It is much more convenient to use the terms kilowatts, megawatts, and gigawatts for power, and kilowatt-hours, megawatt-hours, gigawatt-hours and terawatt-hours for amounts of energy.

Power				
1 kilowatt (kW)	=	one thousand watts		
1 megawatt (MW)	=	one thousand kilowatts	=	one million watts
1 gigawatt (GW)	=	one thousand megawatts	=	one billion watts
Energy				
1 kilowatt-hour (kWh)	=	one thousand watt-hours		
1 megawatt-hour (MWh)	=	one thousand kilowatt-hours	=	one million watt-hours
1 gigawatt-hour (GWh)	=	one thousand megawatt-hours	=	one billion watt-hours
1 terawatt-hour (TWh)	=	one thousand gigawatt-hours	=	one trillion watt-hours

Forecasts* for Electricity Demand in Ontario

(per cent per year, 1987-2000) by Various Organizations

Energy Mines and Resources	3.5%
Ontario Hydro	2.9%
Ministry of Energy	2.8%
Data Resources Incorporated	2.7%
Wharton Econometric Forecasting Associates	2.5%
National Energy Board (1.9% for primary load, equivalent to 2.5% for basic load)	2.5%

** Based on most recently available data, August, 1989*

Agricultural development aided by electricity continues to be part of our economic growth.

Customer lifestyles' needs include energy whether in small towns or large metropolitan cities.

A world-class city has high economic, cultural and energy expectations.

forecasts smooth over short-term changes in economic growth, electricity demand, and other important variables such as fuel prices.

The need for additional load meeting capability, whether on the demand or supply side, should be determined from the long-term perspective.

Given the recent history of very strong load growth in Ontario, there are no major groups with load forecasts which are significantly lower than Ontario Hydro's. In fact, there is a tendency in some quarters to extrapolate from the near 5% growth rate in demand for the past six years. Ontario Hydro believes that it has taken a balanced perspective in formulating its long-term load forecast by carefully separating the cyclical and transitory elements of the economic growth and electrical intensity patterns in the available historical data from the fundamental drivers of the long-term electricity demand.

HISTORY OF ELECTRICITY USE

Electricity and the Economy Since World War II

In order to understand some of the differences between long-term trends and short-term variations, it is useful review how demand has evolved over both the long and short term. Electricity demand in Ontario grew rapidly in the first decade after World War II, averaging growth of 9% per annum between 1946 and 1956 as pent up demand from the war years was met and the transmission network expanded. For the subsequent 20 years (1956–1976), growth rates subsided somewhat averaging a fairly steady 6.7% per year. Then, from 1976–1988, the average annual growth rate in demand fell off sharply, to 3.3%.

Figure 3–1 **10 Year Average Annual Absolute Growth of Energy**
1950-2010 (in TWh)

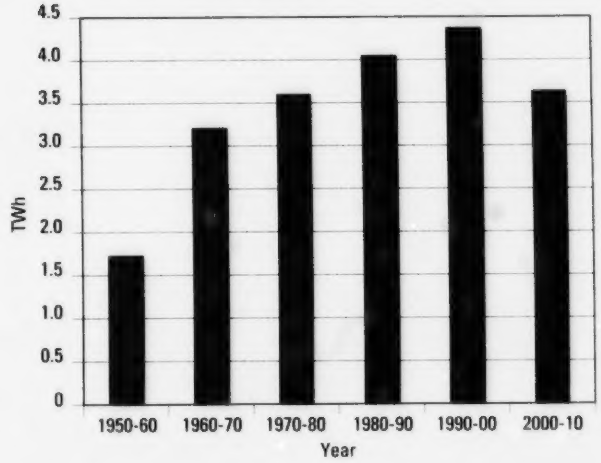
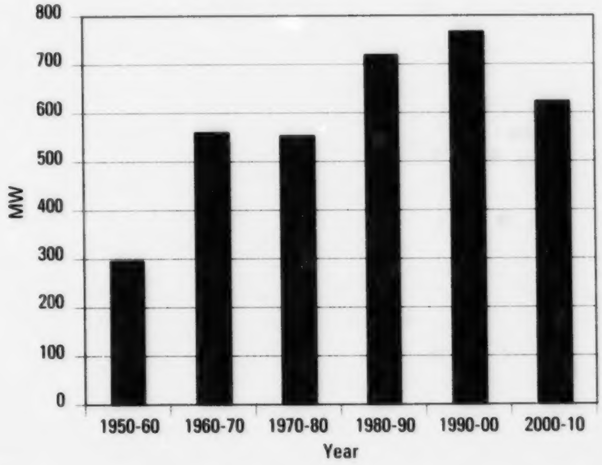


Figure 3–2 **10 Year Average Annual Absolute Growth of System Peak**
1950-2010 (in MW)



Another way to look at electricity sales growth is in terms of the absolute quantity of electricity demanded. In those terms, growth has been much more stable. Despite some fluctuations, absolute growth has averaged about three and a half terawatt hours of energy and 600 megawatts of peak power demand per year since 1960, as shown in Figures 3–1 and 3–2.

These general growth trends are related to the performance of the three key determinants of electricity demand growth: economic activity, electricity prices, and the prices of competing energy forms. In each case, there are sharp contrasts between their performance in the first 30 years after World War II, and the decade or so since then.

During those first 30 years, Ontario experienced a prolonged period of relatively rapid economic growth, as much of the modern industrial infrastructure was built.

At the same time, prices for all forms of energy were falling in real terms at a rate of about two percent per year. That helped electricity sales growth at 7.4 % a year, outstrip economic growth, which averaged 4.7 % per year from the late '40s to the oil shock of the mid-1970s.

Since the mid-1970s, wide fluctuations in basic commodity prices, especially oil, and wide swings in inflation rates in the developed countries have tended to dampen economic growth. Further, real electricity prices rose, although less rapidly than other energy prices.

Electricity Growth by Sector

In analyzing future load growth prospects there is much to be gained for both forecasting and demand management program design by going beyond the analysis of total electricity sales data to examine the trends in the sales of electricity by sector. The components of electricity use by sector are shown in Figures 3–4. (The sector definitions used here are the same as the ones used in Chapter 7 to provide the estimates of demand management impact.) The history of electricity sales for the residential, commercial and industrial sectors for the years 1962 to 1987 is plotted in Figure 3–5. A few examples of the complex trends embedded in this data are presented here.

The most notable feature of sectoral load growth in this period is the very rapid growth in the commercial sector relative to the industrial sector between 1962 and 1977. In that time interval, while total system load growth averaged 6.6%, the commercial sector grew at 10.4%, the residential sector at 6.1% and the industrial sector at 4.2%. The high growth rate in the commercial sector relative to the industrial sector boosted the commercial sector to become almost equal to the industrial sector in electricity consumption by the late 1970s. Since 1977, electricity demand in all three sectors has grown at about the same rate on average.

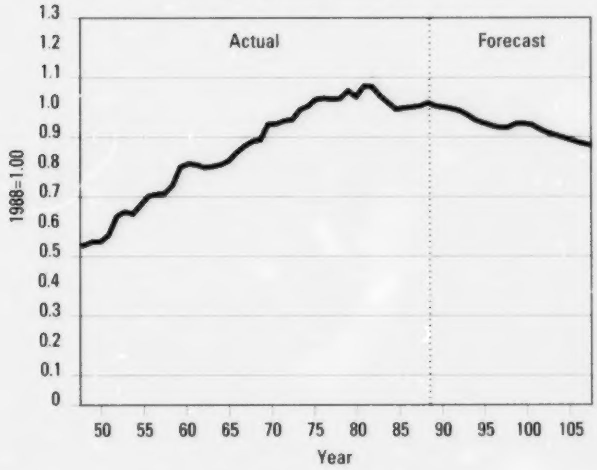
The high rate of growth in commercial load between 1962 and 1977 was not due to a more rapid rate of growth of real GDP in the commercial sector; commercial and industrial GDP grew at almost identical rates in this period. Rather, electricity intensity in the commercial sector increased dramatically while that of the industrial sector declined slightly. Construction of commercial building space was extremely rapid and was especially strong for public sector buildings like schools and hospitals. These buildings added significant electric demand, but contributed only modestly to measured economic growth. Other trends also contributed to the rapid electrification of the service sector of the economy at this time.

The industrial sector's fraction of electricity use fell from 51% in 1962 to 38% by 1977 and is the same today. This was primarily because efficiency gains and shifts in industrial make-up caused rapid declines in the overall energy intensity of the industrial sector. Electricity has increased its share of this market when compared to other fuels, but its growth rate has not kept pace with that of industrial output.

Over the past twenty-five years, residential electricity use has grown at about the same rate as total demand. This growth pattern is the result of numerous divergent trends. Residential electricity use grew at twice the rate of growth of the housing stock from 1962 to 1976. Two major trends dominated this period: electric space-heating in new housing went from essentially zero to about 11%, and customer purchases of the major energy using appliances such as electric stoves and clothes washers increased substantially. From 1976 to 1985, residential electricity use per house and relative to income was roughly flat. Efficiency gains in appliances and better insulation of electrically-heated dwellings were offset by continued increases in:

- electricity's share of space heating for new houses (to 20%);
- the larger size of new electrically heated houses (up about 500 sq. ft. in 15 years); and,
- the increased customer adoption of appliances such as clothes dryers, dishwashers and air-conditioners.

Figure 3–3 **Ontario Electricity Intensity**
(kWh per real $GDP indexed to 1.0 in 1988)



Increased population and economic affluence means increased demand.

From the mid-1970s, average annual electricity sales growth of 3.3 % has matched economic growth of 3.3 %.

As these data show, the contrast in economic performance between the first 30 years after World War II and the last 15 years is matched by a contrast in electricity sales growth during those periods. These historical developments underline the importance of the evolving relationship between overall economic growth and the demand for electricity.

Changing Electricity Intensity[†]

The amount of electricity consumed (in kilowatt-hours) per constant dollar of real Gross Domestic Product (GDP) is a measure of the electricity intensity of the Ontario economy. Figure 3–3 plots the history of this ratio from 1947–1988, indexed so that 1988 equals 1.0. It shows that electricity intensity in Ontario increased almost every year until 1982, then fell for five years before starting to rise again. The electricity intensity of the Ontario economy is now almost twice as high as it was at the end of World War II. Roughly half the increase in electricity intensity which occurred over this period had already taken place by 1960. Since then the rate of increase of electricity intensity has been significantly slower. In fact, the reduction in the mid-1980s brought electricity intensity in 1988 back to the 1975 level.

Electricity intensity changes when electricity consumption grows at a different rate from growth in the economy. There are many reasons why this may happen. Several important contributors to changing electricity intensity are the choices by customers (often driven by price) to use electricity rather than other fuels, to change electricity service levels where electricity has no substitutes, and to change the efficiency with which electricity is used. Shifts in the mix of economic activities may also have a significant impact on electricity intensity.

The ratio of the growth rate of electricity consumption to the growth rate of real GDP, which indicates how electricity intensity is changing, is an important characteristic of the load forecast.

FACTORS IN FORECASTING

Major Trends Driving Future Growth

The three most important factors in any model of the demand for electricity in the long run are the projections of the general level of economic activity (GDP), the price of electricity and the prices of other competing fuels. Broadly speaking, the future level of economic activity determines the future demand for energy services. Energy price variables influence the customers' choices regarding fuel, level of utilization and efficiency of equipment.

Growth in the Economy

The long-run growth rate for the economy depends on growth in the number of workers and their productivity growth – the output of economic activity per worker. This section examines these two drivers of economic growth – growth in the labour force, and productivity. This section also reviews recent and longer-term historical trends, and introduces Hydro's forecast for labour force and productivity, and the real GDP outlook which these two factors determine.

Labour Force Growth

For the 30-year period of strong economic growth following World War II, Ontario's labour force grew very rapidly. The major contributing

Figure 3–4 A **How Electricity was used in Ontario (1987)**
Residential

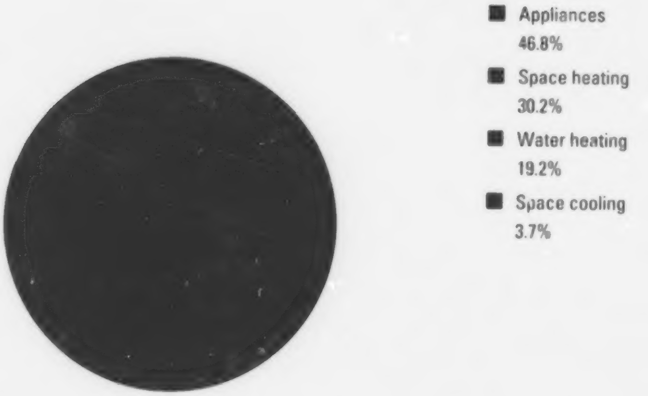


Figure 3–4 B **How Electricity was used in Ontario (1987)**
Commercial

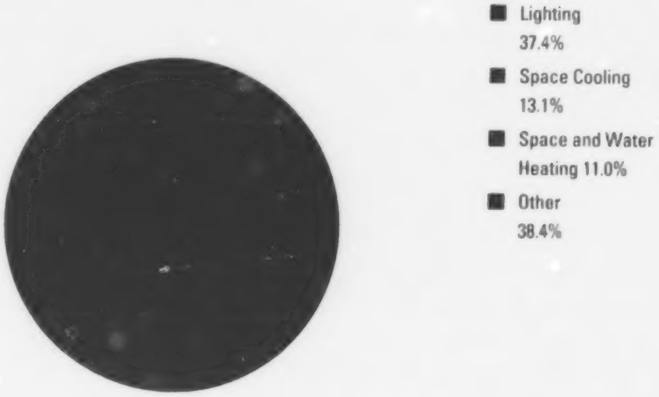


Figure 3–4 C **How Electricity was used in Ontario (1987)**
Industrial

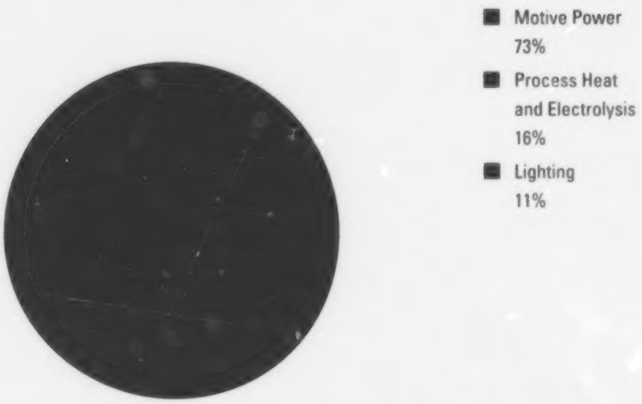
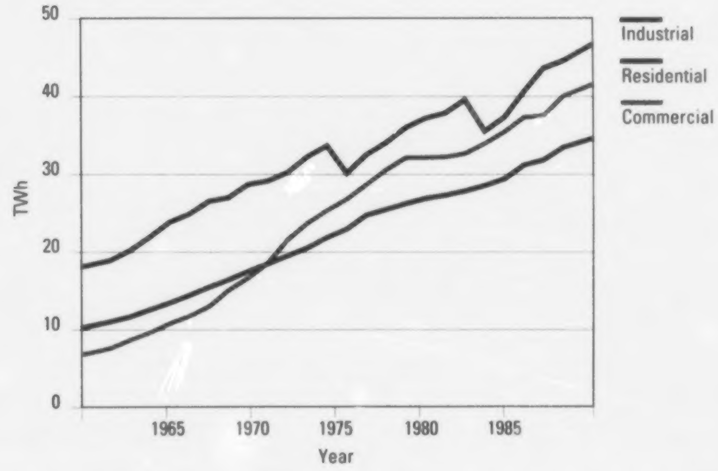


Figure 3–5 **Sectoral Electricity Demand Growth in Ontario (1962-88)**



Three Major Factors in Electricity Growth

1. **General level of economic activity (GDP)**
2. **Price of electricity; and,**
3. **Prices of competing forms of energy.**

factors were the return of servicemen after the war, strong immigration to Ontario in the 1950s and 1960s, the entry of the baby boom age group into the workforce (peaking in the early 1970s) and an increasing rate of participation of women in the workforce.

Since the mid-seventies, the "baby boom" generation has contributed less and less to labour force growth, while immigration to Canada has declined in proportion to total population over this period. Labour force participation rates for women have continued to increase significantly (Figure 3–6), but nonetheless, labour force growth rates of 2.3% per year in the past fifteen years were about 1% slower than in the previous 30 years. This explains part of the slowdown in the economic growth rate noted earlier for this time period.

As the labour force is that portion of the total population between the ages of 16 and 65 which is actively seeking work, Ontario Hydro's forecast of future labour force growth rates is derived from a population projection produced by a detailed demographic model for Ontario. This model begins with an age and sex specific profile of the Ontario population and takes into account future trends in fertility, mortality, net immigration into the province and labour force participation rates.

The labour force growth rates which drive the long-term economic outlook decline fairly

The labour force growth rates which drive the long-term economic outlook decline fairly steadily over the forecast horizon, falling from over 2% per year in the late 1980s, to 1% per year by the turn of the century to almost zero growth per year beyond 2010. This trend is largely a natural outcome of the aging of the "baby boom" group and the saturation in the labour force participation of women.

steadily over the forecast horizon, falling from over 2% per year in the late 1980s, to 1% per year by the turn of the century to almost zero growth per year beyond 2010. This trend is largely a natural outcome of the aging of the "baby boom" group and the saturation in the labour force participation of women.

The labour force growth forecast is summarized in Figure 3-7.

Productivity Growth

Between 1945 and 1975, Ontario's economy industrialized rapidly. The shift from an agricultural to an industrial economy brought with it higher output per worker. Mechanization and other technological developments on the farm as well as in industry increased worker productivity.

Patterns of productivity growth reflect a similar pattern to labour force growth rates. Increases in productivity were high from just after the war until the early 1970s, averaging 1.8% per year. Since then, the rate of growth of output per worker has been far below the long-term average, averaging about 0.7 % per year. Productivity growth was stagnant in Ontario between 1972 and 1982.

Ontario Hydro's forecast of productivity growth, the second component of economic growth, is a relatively stable 1.6% per year and is based on a long-term historical perspective.

It is only slightly below that achieved in the strong period of industrialization following World War II. The long-term economic forecast concludes that the factors which brought about the flat productivity performance of the 1970s are not indicative of the future. On the other hand, the increased role of the service sector in the forecast period, relative to the

Figure 3-6 **Female Labour Force Participation Rates for Ontario**

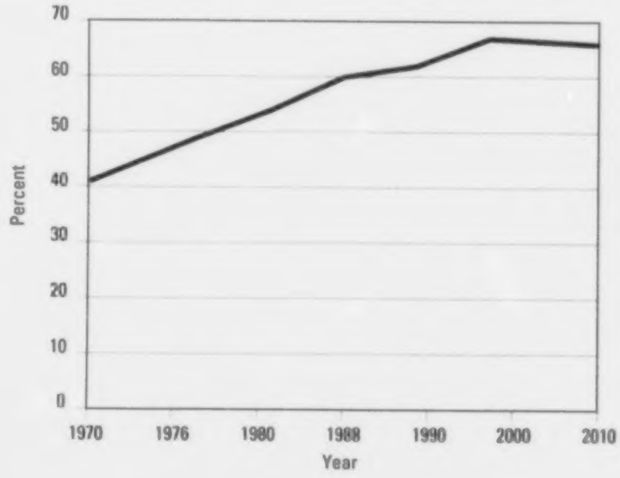


Figure 3-7 **Economic Data (Average Annual Growth Rates)**

	Ontario Real GDP	Labour Force Growth	Employment	Productivity
1980–1988[1]	4.3	2.1	2.3	1.9
1982–1988[1]	5.9	2.2	3.0	2.7
1988–2000[2]	3.2	1.5	1.6	1.6
2000–2010[2]	2.2	0.7	0.7	1.5
1988–2010	2.7	1.1	1.2	1.6

[1] *May, 1989 Economic Outlook (Updated Historical Data)*
[2] *September, 1988 Economic Outlook*

Figure 3-8 **Ontario Retail Energy Prices (Residential)**
(Real $ 1988 Average Annual Growth Rates)

	Electricity	Natural Gas	Oil
1980–1988	0.5%	–0.2%	2.2%
1982–1988	1.1%	–2.8%	–3.0%
1988–2000	–0.2%	1.8%	1.2%
2000–2010	–0.2%	1.2%	0.7%
1988–2010	–0.2%	1.5%	1.0%

Source: Retail Energy Price Trends, October 1988

post-war average, reduces slightly the expectations for productivity growth, given the tendency for slower productivity growth in services as opposed to goods production.

Real GDP Growth

To forecast long-term economic growth prospects, Ontario Hydro combines its forecast of labour force growth and productivity growth to yield the results shown in Figure 3–7. For the remainder of the century, Hydro expects Ontario's real GDP to grow at an average annual rate of 3.2% per year, driven about equally by productivity gains and labour force growth. Beyond 2000, growth is forecast to be about 1% slower, due to the decline in labour force growth rates.

The strong contrast between the long-term economic growth forecast and Ontario's outstanding economic performance in the 1982 to 1988 period, when real GDP grew at nearly 6% per year, bears some scrutiny. The divergence between the recent experience and the long-term outlook is a good example of the need to take a long-term historical perspective in preparing a forecast as far into the future as is required in this Plan.

Labour force and productivity growth since 1982 reflect factors that cannot be sustained over the long term, and which therefore make extrapolating trends from the last six years unreasonable.

In 1982, Ontario experienced its deepest recession since the Great Depression. Economic activity dropped 4.2% and the unemployment rate averaged 10.3%. Since then, the Ontario economy has rebounded in the most dramatic trough-to-peak recovery of any business cycle in Ontario in 50 years. This recovery had a number of causes which cannot be repeated in the next few years.

Ontario Hydro's forecast of productivity growth, the second component of economic growth, is a relatively stable 1.6% per year and is based on a long-term historical perspective.

In a fully-employed economy (unemployment rate about 4%), labour force growth and employment growth are identical. During 1982 to 1988, employment growth (3.0%) was much higher than labour force growth (2.2%). This was made possible by the absorption back into the workforce of the large pool of unemployed workers. As they found jobs, the unemployment rate fell from 10.3% to about 5.0%. On top of this was the boost to the labour force given by return of workers from the West as oil prices collapsed, and a much higher than normal share of national immigration. With the possible exception of external immigration, these extra boosts to output are not available to contribute their effects in the years ahead.

Productivity growth during the period 1982 to 1988 was also very high (2.7%) and reflected conditions unique to the recovery period, namely the utilization of idle manufacturing capacity, capital catch-up after a long period of sluggish capital expansion from the late 1970s, and the reduction in production costs made possible by the sharp decrease in oil and natural gas prices.

Ontario Hydro's long-term GDP forecast has recognized the cyclical elements in the growth of the past six years and taken a longer-term historical perspective.

Prices of Electricity and Competing Fuels

Another major driver for electricity demand is the price of electricity, both in absolute terms, and relative to other forms of energy. The projected trend in real electricity prices is summarized in Figure 3–8.

Real electricity prices dropped about 30% right after the Second World War and then declined steadily at a rate of about 1.5% per year until the mid-1970s, promoting the increased use of electricity. In 1976 to 1977 real residential retail prices jumped about 25% and have been roughly stable since. Given the relatively stable projection for electricity prices for the next twenty years, electricity price changes have only a small effect on the load forecast.

Prior to the completion of the Trans-Canada Pipeline in 1959, the energy market in Ontario was dominated by oil, electricity, and coal. The natural gas distribution system has expanded rapidly in the last 30 years, and natural gas now supplies about 35% of Ontario's total energy needs. The expansion in the use of natural gas has been mainly at the expense of oil and coal. Coal use is now restricted to a few large industries. With the rapid increase of oil and gas prices in the late 1970s, the attractiveness of electricity increased significantly in the space-heating market. Electricity made significant gains in areas where natural gas was not available.

Natural gas prices more than doubled in real terms from 1974 to 1983, yet natural gas remained competitive with electricity in the heating markets. Residential prices are now down 20% from their 1983 peak, and the assumption used in developing the December 1988 Load Forecast is that prices are expected to return to that level around the turn of the century. In the range in which natural gas prices are expected to fluctuate, they also have only a small effect on the forecast demand for electricity. The gas prices used for developing the estimates for the supply options are based on data developed during 1989 and are shown in Chapter 14. The difference in gas price assumptions is expected to have only a small effect on the load forecast.

With the decline in the use of oil for space-heating in Ontario, relative price shifts in oil have only a marginal direct impact on the load forecast for electricity. However, oil prices could influence electricity load indirectly. In the event that oil prices rise steeply, this could depress economic activity and reduce electricity demand.

THE LONG-TERM LOAD FORECAST

Recognizing Uncertainty in the Long-term Forecast

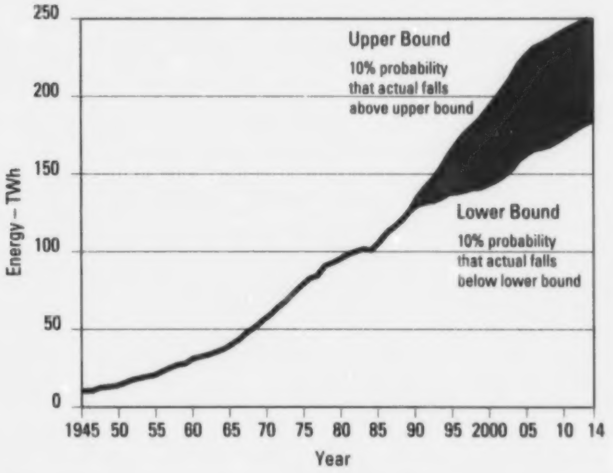
Forecasts of the fundamental drivers of the long-term load forecast are fraught with uncertainty. Electricity use pervades all aspects of the economy and so is sensitive to the scale and nature of the complete spectrum of economic activities. While some trends in the economy tend to stabilize over the longer term, they are still quite volatile, as the variability – from boom to bust – of economic conditions this century, or even this decade, has indicated. In addition, projecting demand involves making predictions about choices consumers will exercise, and that adds to the uncertainty.

Planning to meet future electricity needs must recognize and adapt to the significant uncertainty that surrounds any forecast. A meaningful plan must accept that large deviations from the median forecast are quite probable, in either direction.

Load Forecast Bandwidth

To reflect the uncertainty in the load forecast, a complete probability distribution for each year in the forecast period is provided to assist in developing flexible plans for the future. Hydro's objective is a plan which can meet a forecast bandwidth which contains 80% of the expected future outcomes for load growth. The determination of the uncertainty in the load forecast combines the uncertainties associated with economic growth and electricity consumption.

Figure 3–9 **1988 Basic Load Forecast** Energy Bandwidth



> ***A meaningful plan must accept that large deviations from the median forecast are quite probable, in either direction.***

The final product is a probability distribution for basic energy demand for the forecast period. Figure 3–9 illustrates the bandwidth forecast at the 80% confidence level.

That is, there is estimated to be a 10% chance that actual load growth could exceed the upper bound of the range and a 10% chance that it could be less than the lower bound of the range; the remaining 80% probability is covered by the forecast bandwidth.

Figure 3–10 illustrates the 1988 Basic Load Forecast of energy in kilowatt hours per year for the bandwidth forecast.

Figure 3-10 **1988 Basic Load Forecast Bandwidth**
Annual Energy (TWh)

Year	Lower (10%)*	Median (50%)*	Upper (90%)*
1989	132	137	142
1990	133	140	147
1991	135	145	154
1992	137	151	162
1993	138	155	169
1994	139	159	176
1995	141	163	180
1996	141	165	185
1997	143	169	192
1998	146	174	198
1999	149	178	205
2000	153	184	212
2001	159	192	221
2002	163	196	227
2003	166	201	231
2004	167	202	234
2005	168	205	236
2006	171	208	240
2007	174	211	242
2008	178	214	245
2009	181	217	247
2010	185	220	250
2011	188	224	252
2012	191	227	255
2013	194	230	257
2014	197	234	260

** Estimated probablity that actual energy will be less than amount forecast*

Figure 3-11 **1988 Basic Peak Power Forecast Bandwidth (GW)**
(20 minute December Peak)

Year	Lower (10%)*	Median (50%)*	Upper Bound (90%)*
1990	22.6	24.0	25.1
2000	26.3	31.7	36.4
2010	31.7	37.9	42.5

** Estimated probability that actual energy will be less than amount forecasted*

Figure 3.12 **1988 Basic Load Forecast Bandwidth**

20-Minute January Peak Power (GW)

Year	Lower (10%)*	Median (50%)*	Upper (90%)*
1989	22.7	23.2	24.0
1990	22.5	23.8	24.9
1991	22.8	24.5	26.0
1992	23.2	25.5	27.4
1993	23.5	26.3	28.7
1994	23.7	26.9	29.8
1995	23.9	27.5	30.8
1996	24.2	28.1	31.6
1997	24.2	28.7	32.6
1998	24.7	29.4	33.6
1999	25.1	30.2	34.8
2000	25.7	31.1	36.0
2001	26.6	32.3	37.4
2002	27.8	33.3	38.6
2003	28.2	34.1	39.5
2004	28.7	34.5	40.1
2005	28.6	34.9	40.6
2006	29.0	35.4	41.1
2007	29.6	35.9	41.6
2008	30.1	36.4	42.1
2009	30.7	32.0	42.5
2010	31.2	37.5	42.9
2011	31.9	38.1	43.3
2012	32.4	38.6	43.8
2013	33.0	39.2	44.2
2014	33.5	39.8	44.7

** Estimated probability that central power will be less than amount forecast*

Note: January, 1989 20-minute January peak was 23.1 GW

Figure 3–13 **1988 Basic Load Forecast**

20–Minute December Peak Power Bandwidth

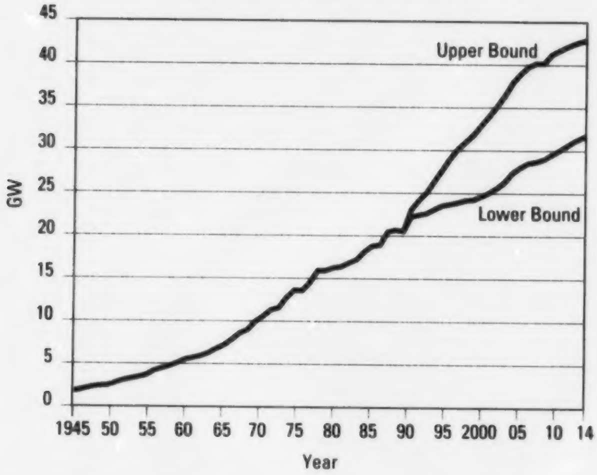


Figure 3–14 **1988 Basic Load Forecast**

Average Annual Growth Rates for Energy (%)

Period	Lower (10%)*	Median (50%)*	Upper (90%)*
1987–1995	1.34	3.19	4.54
1987–2000	1.47	2.93	4.05
1987–2010	1.66	2.44	3.00
1987–2014	1.66	2.30	2.71

* *Estimated probability that actual energy will be less than amount forecast*

Figure 3–15 **1988 Basic Load Forecast**

Average Annual Absolute Growth for Energy (TWh per year)

Period	Lower (10%)*	Median (50%)*	Upper (90%)*
1987–2000	2.0	4.4	6.6
2000–2014	3.2	3.6	3.4
1987–2014	2.6	4.0	4.9

** Estimated probability that the actual energy will be less than the amount forecast.*

In addition to energy, a bandwidth forecast is prepared for peak power. The Basic Load Forecast values for 20-minute December peak power for selected years are provided in Figure 3–11.

Details of the Load Forecast are contained in the reference document, Load Forecast 881212. Details of the development of the bandwidth are contained in the reference report, "Uncertainty in the Load Forecast". In the body of that report, peak demand is quoted for the calendar year annual peak, which usually occurs in December. However, for planning purposes, it is more practical to consider the winter peak which occurs on the coldest winter day, typically in January. Throughout the remainder of this report, peak load data are quoted for the 20-minute peak in January. For example, the January, 1990 peak refers to the peak day in the winter of 1989/90.

Figure 3–12 gives the Basic Load Forecast for January peak for each year in the planning period.

A plot of the bandwidth for the peak load forecast is provided in Figure 3–13.

With the underlying economic projections described in Figure 3–7 for Ontario economic growth, the labour force, employment, and productivity, the median basic load growth is forecast to average 2.9% per annum from 1987 to 2000 and 2.4% per annum from 1987 to 2010 (Figure 3–14). January peak demand increases from 22.6 GW in 1988 to 31.1 GW in the year 2000 (710 MW per year) and then to 39.8 GW in 2014 (620 MW per year from 2000). In energy terms, the forecast increase is from 126.5 terawatt hours in 1987 to 184.1 in 2000 (4.4 TWh per year) and to 233.8 in 2014 (3.6 TWh per year from 2000).

The growth rate to the year 2000 for basic demand declines from 3.5% per year on average for the first five years of the forecast (1988 to 1993) to 2.5% per year for the last five years. Load growth since 1980 has averaged 3.7 % per year, but has been stronger, at 4.9% since the recession of 1982. Earlier discussion indicated why it was unlikley that the 5.9 % annual economic growth rate for the 1982 to 1988 period could be sustained for another five years. Hydro's forecast of a declining electricity growth rate reflects lower rates of economic growth for the 1990s (3.2%) than for the 1980s (4.3%). The major reasons are slower growth in productivity, population, and workforce. Trends in electrical intensity are also important and are examined in the following section.

Despite the forecast declines in year-over-year electricity growth, absolute growth in energy and peak demand are forecast to remain relatively constant. Figures 3–1 and 3–2 show the historical average growth for the decades from 1950 to the present, and the forecast absolute growth to 2010. Figure 3–15 gives the forecast average absolute growth for energy.

Electricity and Economic Growth

Since 1980, electricity demand has grown at an average annual rate of 3.7%, while the economy expanded at 4.3%. The ratio of these growth rates is 86%.

There are two contrasting intervals during this period. From 1982 to 1986, electricity demand grew at only about 70% of economic growth, but in the last two years it jumped to about 120% of economic growth.

This swing in the electricity intensity of economic growth is in part due to the impact of the commercial and residential building boom which took place from 1986 to 1988 after very weak building activity from 1982 to 1985. These high rates of construction were well above the long-run rate and are in a sense making up for underbuilding in the first half of the 1980s, a period of very high interest rates. The rate of connection of new buildings to the electrical system is a significant factor in determining short-term swings in electricity intensity.

Strong commercial and residential building starts are forecast to continue for several years, though down 20-25% from the peak in 1987. As a result, the electricity demand growth rate is expected to remain above the GDP growth rate until 1991 and then begins to move toward

Today's modern technology means higher productivity and a higher demand for electricity.

the long-run ratio of about 90% of GDP as indicated by Hydro's long-term forecasting models. This forecast change in electricity intensity is shown in Figure 3–3.

The recent fluctuations in electricity intensity of economic growth argue strongly for a long-term perspective on this key element of the load forecast, as well as a detailed sectoral or end-use approach to load forecasting. In order to capture more of the complexity of factors and trends associated with forecasting, Hydro has developed two main techniques, described in the next section.

FORECASTING METHODOLOGY

Modelling Electricity Demand

Ontario Hydro takes two approaches to estimating long-term electricity demand: "top-down" econometric modelling and "bottom-up" end-use modelling. Both attempt to capture the effect of a large number of demographic, economic, energy market and technological factors on electricity demand in the long run.

The econometric approach relies on statistical analysis of past energy consuming behaviour and forecasts of broad economic aggregates to generate estimates of future electricity requirements. In the end-use approach, the forecast is based on expert opinion applied to key technology or market trends, combined with very detailed forecasts of the activity levels underlying the ways in which electricity is used.

The econometric model approach is capable of simulating macro scenarios that result from different assumptions about key input variables such as GDP. On the other hand, end-use modelling may more readily identify significant changes in demand trends due to technological change or compositional shifts.

The need for the load forecast to be tied to a broad scenario for the economy and at the same time be sufficiently detailed to be useful for analyzing demand management opportunities has led to the use of econometric methods within end-use models. As techniques become more sophisticated, the distinction between the two is softening.

Because Hydro uses both end-use and econometric modelling systems in preparing the long-term Basic Load Forecast, the strengths and weaknesses of these models are weighed and their results integrated in order to arrive at a recommended forecast for planning purposes.

The Econometric Model: A Top-Down Approach

The econometric forecast of electricity demand in Ontario is produced by Hydro's Econometric Energy Model for Ontario (EEMO). EEMO takes as inputs forecasts of 13 final demand categories for the Ontario economy (for example, consumption of durable goods and non-residential investment). These are processed to derive forecasts of total energy requirements for each of the industrial and commercial sectors on the assumption that technology and productivity remain constant at 1971 levels. This static forecast is then adjusted to reflect the impact of changing technology and prices.

Forecasts of electricity prices and other fuel prices contribute to determining electricity's future market shares. The product of electricity market share and total energy requirements determines electricity demand for each sector. Demographic forecasts are important in determining the total energy requirements in the residential sector.

Figure 3–16 summarizes the sector forecasts for the econometric model. The resulting Basic Energy Forecast averages 3.1% annual growth to the year 2000 and 2.6% over the entire forecast period to 2010, a rate which is 0.1% per year slower than the GDP forecast growth rate.

The End-use Model: A Bottom-up Approach

End-use modelling uses a "bottom-up" approach to energy analysis. It starts with the initial stock of energy using devices and an estimate of future demand for the services required of these devices. The energy conversion efficiency of existing equipment, customer adoption of new technologies, typically with higher efficiency, and relative fuel share for each end use are analyzed. Trends in electricity use per household, per square foot of commercial floor-area and by industrial process are combined with forecasts of activity for each sector to arrive at the final demand estimate.

Each of the major energy using sectors is modelled separately. This analysis requires forecasts of sectoral activity levels such as residential housing stock and commercial floor space by building type and industrial output in physical units. Factors such as population, labour force, disposable income and detailed forecasts for service and industrial sector economic growth are considered.

Figure 3–16 contains the forecasts by sector using the end-use model. Details of the forecast are provided in the 1988 Load Forecast Report.

Figure 3–16 **1988 Basic Load Forecast by Sector**

Average Annual Energy Growth Rates (%)

	End-Use	EEMO	Basic Load Forecast
Residential			
1987–2000	2.6	2.4	2.6
1987–2010	2.1	1.8	2.1
Commercial			
1987–2000	2.7	4.2	3.3
1987–2010	2.2	3.3	2.7
Industrial			
1987–2000	2.8	2.5	2.5
1987–2010	2.3	2.5	2.5
Total Basic Load			
1987–2000	2.7	3.1	2.9
1987–2010	2.2	2.6	2.4

Preparing an Integrated Forecast

The econometric approach uses more aggregated data than the end-use models. These data are of higher quality and support sophisticated statistical analysis. The models built tend to capture long-term trends, but may be slow to pick up changes in trends that are evident at a more detailed level of analysis. In the forecast period, the implications of projected shifts within sectors can be captured by end-use models more readily than by econometric models.

End-use analysis tends to focus on well-established uses of energy for which data are available. Unless care is taken, there is a tendency to underplay new uses of energy for which forecasts must be highly speculative. The trends in the traditional uses such as appliances, lighting or heating may be well understood, but the implications of a new generation of business machines may not. The econometric models, which focus on macro patterns and factors, use electricity consumption data that implicitly embody a continuously evolving mix of old and new uses of electricity.

To some extent econometric models do not capture some rapid advances in efficiency made possible by new technologies, which end up being adopted in Ontario, but which were developed in other countries where electricity prices and other economic factors give efficient use a higher priority. To that extent, econometric models may be considered to have a tendency to over-forecast. On the other hand, to the extent that end-use models understate the future role of currently embryonic uses of electricity, they may tend to under-forecast.

Figure 3–16 indicates the results of both models. The final Basic Load Forecast reflects the higher of the two forecasts to 2010 for each of the residential (end-use) and industrial (EEMO) sectors. In these sectors, the two models provide similar projections. The commercial forecast is a compromise between the two model systems in the face of the large degree of uncertainty concerning the net effect of efficiency gain in the major end-uses (e.g. lighting, heating, air conditioning) and the rapid expansion of miscellaneous uses (e.g. ventilation, refrigeration, office machines, computers). By giving equal weight to the two models in rationalizing the large discrepancy between their commercial sector forecasts, the overall forecast results in an equal weighting of the two approaches.

Developments in End-use Modelling

Ontario Hydro prepared its first end-use forecast in 1981 with a model adapted from the system used by the Ministry of Energy. In 1986, Ontario Hydro began to adopt new and more advanced end-use load forecasting models developed by the Electric Power Research Institute. The choice, energy efficiency, and utilization of electricity-consuming equipment are modelled directly using basic economic principles of cost minimization and consumer behaviour. In addition, fuel prices are an explicit input.

In 1988, for the first time, forecasts using these models were produced and used to provide insights into the updating of the existing end-use models. Hydro's end-use model development program continues to improve. The current versions are a substantial improvement from a forecasting perspective. Hydro intends to improve these models further to enhance their ability to represent end-uses and technologies at the level of detail of demand management programs.

This is a critical element in producing basic and primary forecasts which are consistent in their relative assumptions and which can, therefore, fully reflect the net impact of demand management programs. As more data are collected and knowledge of energy usage is extended at the detailed technology level, the end-use models will provide a sound framework for the coherent development and analysis of energy demand in Ontario.

Load Forecast Uncertainty

One of the key lessons of the 1970s was that it is extremely risky to plan on the basis of a single line forecast. The dramatic volatility of load growth since the first oil price shock has made it clear that plans that did not consider the full range of uncertainty were vulnerable. The median forecasts made in the late '60s for the late '70s were too high. The median forecasts made in 1982 for the late '80s were too low. These two experiences illustrate the need for bandwidth forecasting and plans which are flexible. Ontario Hydro and other utilities have increased the emphasis on bandwidth forecasting and planning.

To deal with uncertainty in forecasting, an 80% band has been developed. The goal is to describe a range of forecast demand and its probability of occurrence. The size of the bandwidth depends heavily on the uncertainty surrounding growth in the Ontario economy and to a lesser extent on the uncertainty in the estimated relationship between economic growth and electricity demand growth.

A single line forecast is first selected with the intention that it represent the median expected outcome. That is, it produces a scenario for future demand with a 50% chance of being too high and a 50% chance of being too low.

Various techniques are used to take into account the uncertainty of the long-term economic growth forecast and the future relationship between economic growth and electricity demand.

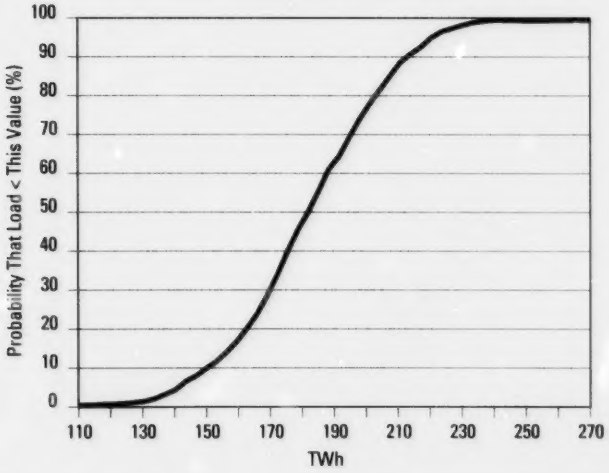
Figures 3–12 and 3–13 illustrate the bandwidths for energy and peak respectively. They show that the 80% bandwidth of the Basic Energy Forecast is about 60 TWh in the year 2000 and 65 TWh by 2010 and the bandwidth for peak demand is about 10 GW by 2000, and gradually spreads to about 11 GW by the end of the planning period.

The 10%, 50% and 90% points are only three points selected from the complete probability distributions generated for each year of the load forecast. An entire load forecast probability distribution is derived specifically for each year of the forecast period.

Figure 3–17 illustrates the cumulative probability distribution of the 1988 Basic Load Forecast of energy for the year 2000. The energy quantities corresponding to the 10% and 90% probability levels are the respective values of the lower and upper bound forecast for that year.

The lower bound forecast is consistent with a view that there is very little likelihood of stagnation in the economy which persists for more than a short period of time. The country's worst experience this century was the three

Figure 3–17 **1989 Basic Load Forecast**
Year 2000 Cumulative Probability Distribution



From Single Line Forecast to Bandwidth

Construction of bandwidths starts from a single line forecast. That forecast is the result of judgments applied to end-use and econometric forecasting model outputs which produce a median load growth forecast. However, the models used to produce the single line forecast are not suitable for generating uncertainty bands.

A much simpler econometric model is used to produce a median forecast and a probability distribution around it. The probability distribution of the load forecast is derived from the probability distribution of GDP and the statistical properties of the equation using "Monte Carlo" simulation techniques. The 80% bandwidth forecast is then determined by taking the 10% and 90% values from the probability distribution for each year of the forecast. The median forecast is not the same as the recommended one resulting from the integration of the two large model forecasts. Therefore, it must be lined up with the recommended median forecast. The bandwidths generated by the simpler model are scaled in a similar way to derive the bandwidths for the recommended long-term forecast.

Figure 3–18 **Daily Load Curve** Typical Winter Day

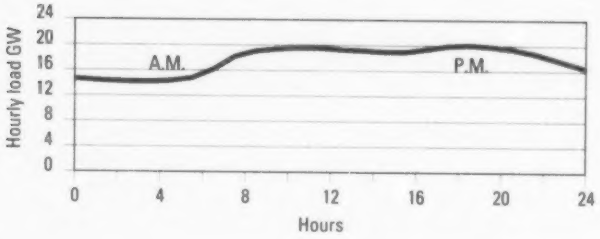


Figure 3–19 **Weekly Load Curve** Typical Winter Week

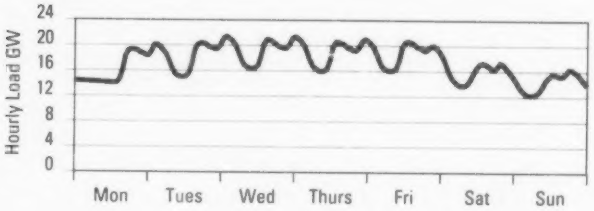


Figure 3–20 **Weekly Load Curve** Typical Summer Week

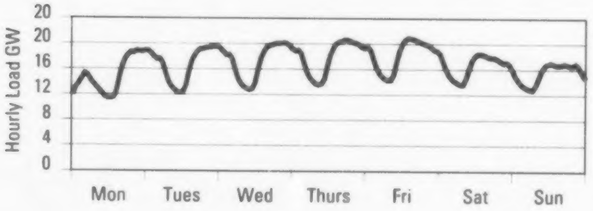


Figure 3–21 **Yearly Load 1988**

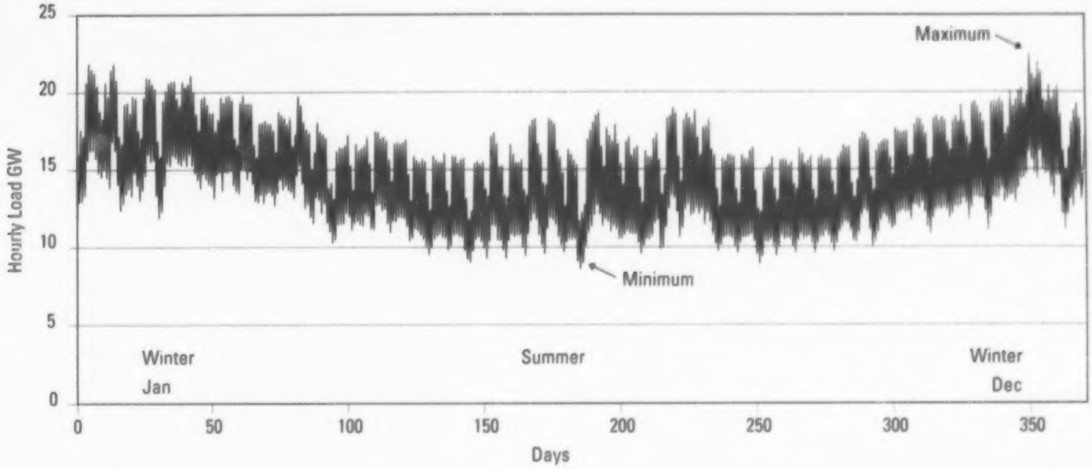
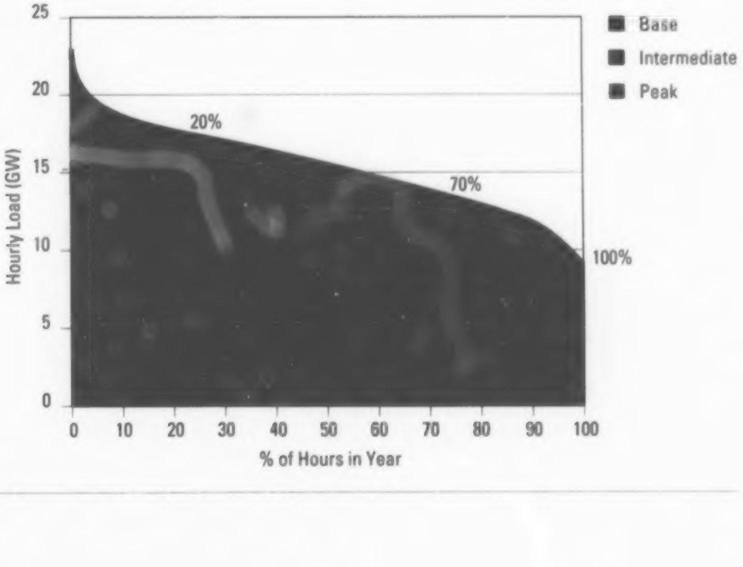


Figure 3–22 **Load Duration Curve**



Increased air conditioning units have contributed to peak demands for electricity in the summer.

Shorter daylight hours increase the use of lights and indoor entertainment in winter.

years of contraction between 1929 and 1932. Since the Second World War, there have been seven periods of contraction each of about one year or less.

The upper bound forecast suggests that the chance of repeating over the next five years the dramatic recent expansion of the economy (5.9% per annum from 1982 to 1988) and growth in electricity demand (4.9% per annum from 1982 to 1988) since the recession of 1982 is about one-in-ten. Recognizing that the forecast begins at a point in time when the Ontario economy is at a peak of the current business cycle, only exceptional circumstances could sustain the current pace for another five years.

The load duration curve

One way of describing how loads vary with time is to break down a year's demand into hour-by-hour segments arranged from the highest hourly load slice to the lowest. This provides what is termed a "load duration curve", as illustrated for a typical year in Figure 3–22. The load duration curve also helps understanding the proposed plans.

As this curve shows, there is a minimum level of demand that must be met at all times and a peak level of demand that occurs for only short periods, with intermediate levels between these high and low values. These are known as the base, intermediate and peak load levels.

The compound average annual growth rate of the upper bound of the range declines as the time horizon is extended, reflecting long-term historical evidence that it becomes less likely that growth rates higher than median expectations can be maintained on average as the horizon extends out from ten to twenty years.

CUSTOMER USE PATTERNS

The development of economic demand/supply plans requires a forecast of the time pattern of customer electricity use.

The demand on the Hydro system represents the combination of loads created by many different end-users in the residential, commercial, and industrial sectors. While this aggregate demand is constantly fluctuating, it does so in a relatively orderly and predictable fashion.

On working days, the load is high between 7 AM and 11 PM. Higher heating and illumination loads make this particularly true in winter as shown for the typical winter day in Figure 3–18. The plot also illustrates that load is lower both at night and on weekends than during the day on weekdays. The highest system load for the province as a whole occurs during the coldest period of the winter. In the urban areas of southern Ontario, where the reliance on air conditioning is the highest, the annual peak load occurs during the hottest part of the summer. The lowest demand for electricity occurs at nights on summer long weekends.

Figure 3–19 illustrates the electricity use pattern for a winter week, and Figure 3–20 for a summer week. Figure 3–21 illustrates the electricity pattern over an entire year.

To develop plans, the forecast customer use pattern is rearranged into a "load-duration curve." The load-duration curve (Figure 3–22) illustrates the need for demand/supply options to meet base load, intermediate load, and peak load.

MAIN FEATURES OF THE BASIC LOAD FORECAST

The main features are:

- Ontario Hydro's use of advanced forecasting techniques and in-depth analysis of load growth trends has produced a long-term load forecast of energy growth 2.3% per year, 1987 to 2014.
- There is uncertainty in the forecast, and it is possible to characterize this uncertainty with probability bandwidths. For planning purposes, an 80% probability bandwidth was identified as an appropriate range.
- The load forecast corresponds to average annual absolute growth of about the same magnitude as that experienced in the 1980s, that is, about 700 megawatts per year for peak power and about 4.0 TWh per year for energy. ●

4 THE EXISTING SYSTEM

The purpose of this chapter is to establish the expected power-meeting and energy-meeting capabilities of the existing system over the 25-year planning period. The chapter describes the facilities currently available to meet people's electricity needs.

It also describes how the existing system is used to meet those needs. For the purposes of this report "existing system" is defined to include the committed Darlington Generating Station, planned to be fully in-service by 1993.

Ontario Hydro supplies electricity through an integrated system that comprises generating facilities, transmission facilities, interconnections with neighbouring utilities and distribution facilities to deliver electricity to the customers.

Figure 4–1 shows the location of the major generating stations – those with more than 100 megawatts (MW) capacity. It also shows the routes for the 230 and 500 kilovolt (kV) transmission lines that form the basis of Hydro's provincial grid. In addition, it shows the interconnections with neighbouring systems in Canada and in the United States.

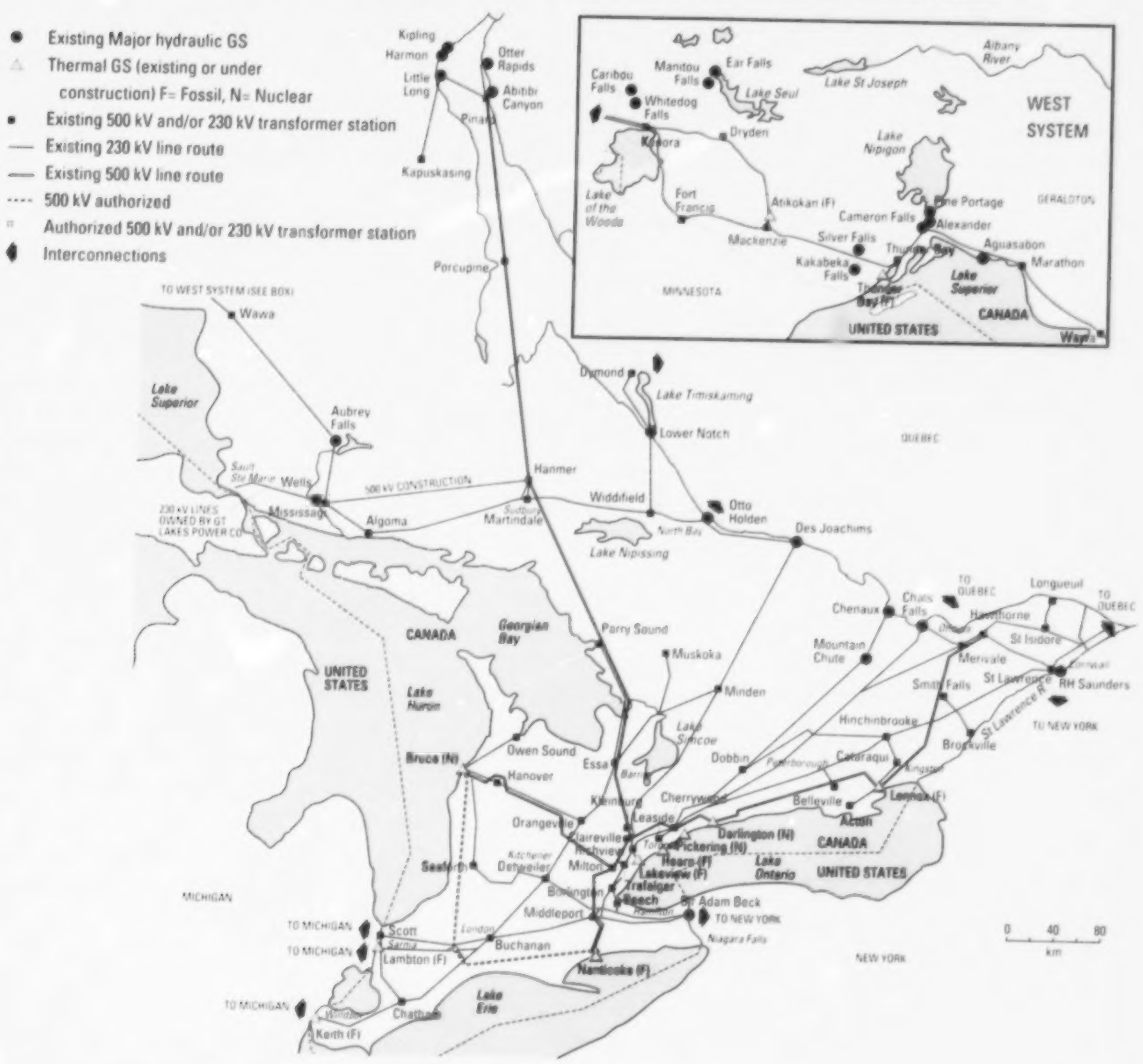
While demand continues to grow and the system is aging, the existing system will continue to be the backbone of the electricity supply during the 25-year planning period. Even at the end of the 25-year period, the existing system is expected to meet about two-thirds of the total primary energy demand† for the median load forecast.

The Demand/Supply Planning Strategy gives a high priority to the maintenance, upgrading and refurbishment of the existing generation and transmission facilities to improve their performance, efficiency, reliability and environmental acceptability.

Rehabilitations of existing facilities are planned to restore performance which has declined due to operational deterioration and to meet new environmental and safety requirements. However as stations become older they are expected to become economically obsolete because of the need for excessive maintenance and refurbishment to meet existing and new operational requirements. The existing stations would not have the benefits of the latest technological developments available to new stations and, as a result, would likely be retired and replaced. The cumulative effect of aging stations is that the ability of the existing system to meet people's electricity needs will decline over the years and replacements must be planned.

Meeting electricity needs is not just a case of providing enough capacity. The production of energy must also be low cost and environmentally acceptable. These considerations are fundamental in deciding how to operate the existing system which, in turn, affects decisions on future facilities.

Figure 4–1 **Ontario Hydro Major Stations (greater than 100 MW capacity) and 500kV and 230kV Line Routes (mid 1989)**


● Existing Major hydraulic GS
△ Thermal GS (existing or under construction) F= Fossil, N= Nuclear
■ Existing 500 kV and/or 230 kV transformer station
— Existing 230 kV line route
— Existing 500 kV line route
---- 500 kV authorized
□ Authorized 500 kV and/or 230 kV transformer station
◆ Interconnections
Kipling
Harmon
Little Long
Otter Rapids
Abitibi Canyon
Pinard
Kapuskasing
Porcupine
TO WEST SYSTEM (SEE BOX)
Wawa
Lake Superior
Aubrey Falls
Sault Ste Marie
Wells
Mississagi
230 kV LINES OWNED BY GT LAKES POWER CO
Algoma
500 kV CONSTRUCTION
Hanmer
Sudbury
Martindale
Dymond
Lake Timiskaming
Lower Notch
Widdifield
Otto Holden
North Bay
Lake Nipissing
Des Joachims
QUEBEC
CANADA
UNITED STATES
Georgian Bay
Lake Huron
Parry Sound
Muskoka
Minden
Lake Simcoe
Barrie
Essa
Owen Sound
Bruce (N)
Hanover
Dobbin
Peterborough
Cherrywood
Kleinburg
Leaside
Orangeville
Claireville
Richview
Toronto
Pickering (N)
Darlington (N)
Hearn (F)
Lakeview (F)
Trafalgar
Beach
Seaforth
Kitchener
Detweiler
Milton
Burlington
Hamilton
Middleport
Sir Adam Beck
TO NEW YORK
Niagara Falls
Nanticoke (F)
Lake Ontario
Lake Erie
MICHIGAN
TO MICHIGAN
TO MICHIGAN
TO MICHIGAN
Scott
Sarnia
Lambton (F)
London
Buchanan
Chatham
Windsor
Keith (F)
Belleville
Acton
Lennox (F)
Kingston
Cataraqui
Hinchinbrooke
Brockville
Smith Falls
St Lawrence
St Lawrence R
Cornwall
RH Saunders
TO NEW YORK
Merivale
St Isidore
Hawthorne
Ottawa
Longueuil
TO QUEBEC
TO QUEBEC
Chats Falls
Chenaux
Mountain Chute
NEW YORK
0 40 80
km
Caribou Falls
Manitou Falls
Ear Falls
Lake Seul
Whitedog Falls
Kenora
Dryden
Lake St Joseph
Albany River
WEST SYSTEM
Lake Nipigon
Lake of the Woods
Fort Francis
Atikokan (F)
Pine Portage
Cameron Falls
Alexander
GERALDTON
Mackenzie
Silver Falls
Kakabeka Falls
Thunder Bay
Thunder Bay (F)
Aguasabon
Marathon
Lake Superior
MINNESOTA
UNITED STATES
CANADA
Wawa

Existing System – Capacity

Ontario Hydro's generating stations are of three types: hydraulic, fossil and nuclear. Hydraulic stations produce electrical energy from falling water. Fossil stations generate electricity by burning coal, oil or natural gas. Nuclear stations use uranium to generate electricity from nuclear energy.

Generating stations are designed to a certain power size or capacity, measured in megawatts. Some small hydraulic stations have a capacity of as little as one megawatt or less. Major nuclear and fossil stations have several generating units providing a total station capacity of up to about 4300 MW.

As shown in Figure 4–2, Hydro will have a total installed capacity of 32.5 gigawatts (GW) by 1993, when Darlington is completed. This total excludes 1.5 GW of older, inefficient gas- and coal-fueled capacity with high fueling, labour and maintenance costs at the Keith and Hearn Generating Stations.

Hydraulic Generation:

By 1993, Hydro's hydraulic capacity will be about 6.5 GW, representing 20% of the system's capacity. This is provided by 265 generating units at 68 stations. The unit sizes vary from less than one megawatt to 130 MW and the station capacities vary between 0.84 and 1290 MW.

Most of the existing hydraulic generation was developed by the 1960s. Since the 1960s, it has formed a declining proportion of the system as a whole, since other types of generation have grown significantly in the intervening period.

Fossil Generation:

Hydro has about 11.9 GW of fossil-fueled generating capacity, representing 37% of the total system capacity that will be in place by 1993. This fossil capacity is provided by 28 major units located at six generating station sites. The 28 fossil units range in size from 100 to 560 MW in capacity. The fossil stations vary in size from 215 to 4336 MW.

Some stations have oil-fueled combustion turbine units (CTUs) installed to assist in station start-ups and shutdowns. CTUs at nine stations, totalling 260 MW, can also provide electricity to the system.

The fossil generation, by fuel type, is:

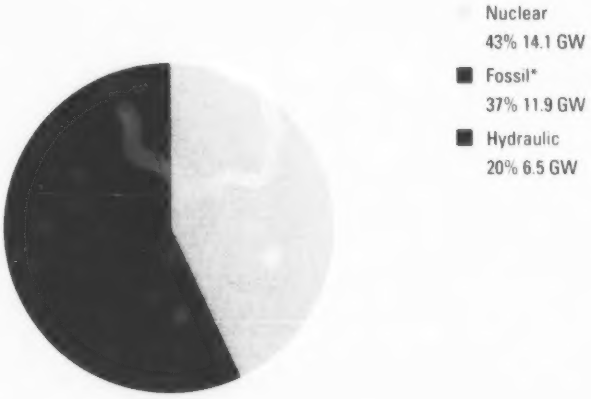
• Coal – conventional steam cycle	9.4 GW
• Oil – conventional steam cycle	2.2 GW
• Oil – CTUs	0.3 GW

Two older fossil stations with high operating costs have been mothballed. These are:

• J.C. Keith	256 MW	coal-fueled.
• R.L. Hearn	1180 MW	gas and coal-fueled.

Hydro will have a total installed capacity of 32.5 gigawatts by 1993, when Darlington is completed.

Figure 4–2 **1993 System Capacity 32.5 GW**



* Coal 29% (9.4 GW) + Oil 8% (2.5 GW)

Mothballing is a way of preserving for future use economically obsolete units or units with high operating costs. It is sometimes preferable to mothball units for possible use in contingencies rather than to decommission† them.

Nuclear Generation:

By 1993, there will be about 14.1 GW of nuclear capacity in service, representing 43% of the system total. This capacity is provided by 20 units located at five stations on the Pickering, Bruce and Darlington sites. The nuclear units, which range from about 500 to 881 MW in capacity, are all of the CANDU design. Station sizes range from 2000 to 3500 MW.

CANDU is a Canadian designed generating station concept for producing electricity from the nuclear energy contained in natural uranium fuel. It uses heavy water for heat transfer and as a moderating agent. One of the major features of the CANDU reactor is the use of pressure tubes rather than a pressure vessel. Stringent attention is given to quality control in design, manufacturing, construction and operation. However, the CANDU concept is based upon the assumption that infrequent mistakes will be made by designers, manufacturers, builders and operators. The design and operation assures public safety assuming components will fail. This includes the failure of pressure tubes.

Total Generation:

A list of all Hydro's generating stations is included at the end of this chapter (Figure 4–20).

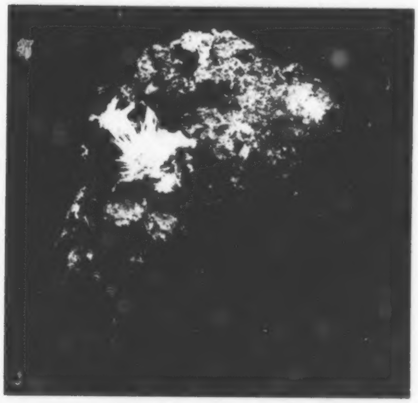
Generation Development 1950 to 1993

An integral part of the province's development over the last four decades, Hydro's generating capacity has grown and diversified as new fuels and generation types have been added. The growth of Hydro's generating capacity from 1950 to 1993 is illustrated in Figure 4–3.

By 1993, the Darlington nuclear generating station, Hydro's only new generating facility under construction, will be completed.

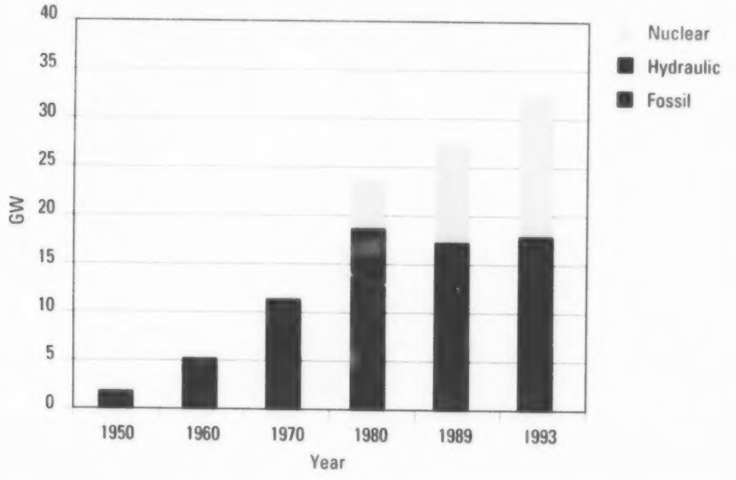
Existing System – Energy

In planning the system, it is not only important to have sufficient generating capacity to meet the instantaneous power requirements, it is equally important to provide the energy requirements on an hour-to-hour basis in an economical, reliable and environmentally acceptable manner.



Currently about half of Ontario's electricity is produced by uranium.

Figure 4–3 **Ontario Hydro Generating Capacity**



Capacity measures the amount of power, in megawatts (MW), that a unit can produce at any instant. Energy is the amount of electricity that is delivered to meet people's electricity needs and is equal to the power multiplied by the time over which it is delivered. Energy is measured in terawatt hours (TWh).

Capacity factor† is a measure of the use of a generating facility. It expresses, as a percentage, how the actual energy produced compares with the energy the facility could have produced if operated continually at full power.

$$\% \text{ Capacity factor} = \frac{\text{Energy}}{\text{Capacity} \times \text{Time in period}} \times 100$$

This section describes:

- the pattern of existing energy demand; and
- how the different forms of generation are used to meet the energy demand.

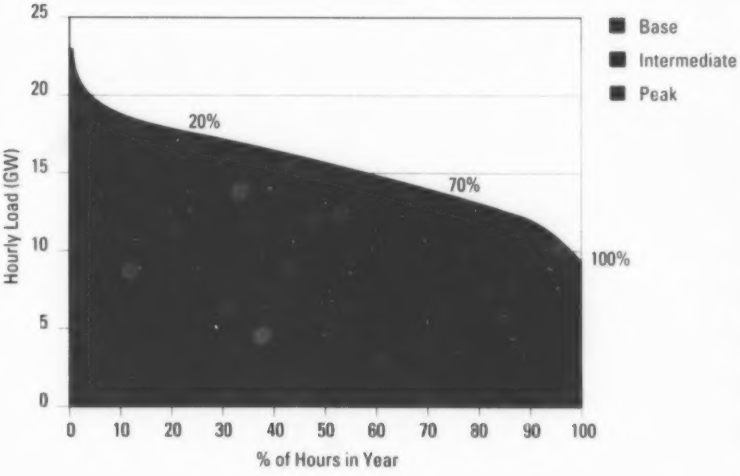
Customer Use Pattern

People's electricity needs are the major factor determining the use of Hydro's supply system. There is a rising and falling pattern of demand as people use electricity in their daily lives. As noted in Chapter 3, this pattern can be described by an annual load duration curve.

During the year there is a minimum level of power demand that must be met at all times and a peak level of demand that occurs for only short periods, with intermediate levels between these low and high values. These are known as the base†, peak† and intermediate† load levels.

These load levels correspond roughly to three different types of generation. The base load, which occurs 70 to 100% of the time, is served by base load generation. Peaking generation is used to supply periods of high

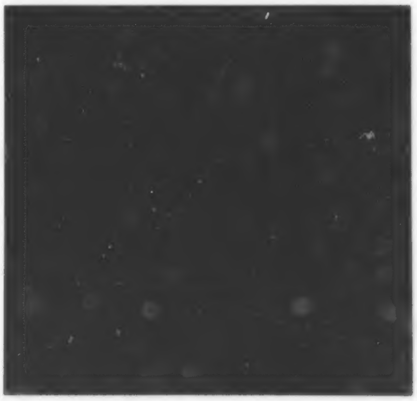
Figure 4–4 **1988 Load Duration Curve and System Load Requirements**



Generation Development

In the first half of the century, electricity needs were met with hydraulic generation. In the period from 1950 to 1975, fossil generation played a major role in meeting growing needs. Since 1970, nuclear generation has played an increasing role.

Once the sole source of power hydraulic now produces 23% of Ontario's electricity.



Fossil-fuelled generating stations provide the system with the flexibility required to meet peak loads or cover outages at other plants.

electricity use, known as peak loads, which occur less than 20% of the time, mainly during daily peaks and winter weekdays. Intermediate generation supplies the intermediate load that occurs between 20 and 70% of the time.

For example, Figure 4–4 shows that, in 1988, the demand was over nine GW 100 percent of the time and over 14 gigawatts 70 percent of the time. It also shows that the demand was over 17.5 gigawatts 20 percent of the time and that for a few hours the load was above 22 gigawatts. The quantity and proportions of peak, intermediate and base load plant are also affected by other factors such as the unavailability of generating stations.

How Hydro Utilizes the System to Meet Varying Demand

It is important to keep the costs as low as possible while running the stations to meet varying demand. Hydro fully utilizes hydraulic generation, followed by nuclear and finally fossil generation which act as "swing" units to fill in any remaining customer needs. The basic economic principle is that generation with the lowest variable costs (largely fuel costs), is operated to the maximum extent, while generation with the highest variable costs (high fuel costs) is operated the least.

The annual energy provided by Ontario Hydro generation, for the period from 1950 to 1993, is illustrated in Figure 4–5.

Figure 4–6 shows the amount of energy expected to be produced in 1993 from hydraulic, nuclear and fossil generation to meet Ontario's needs, excluding non-firm purchases and exports.

Figure 4–7 shows the energy capability of the installed generating capacity in 1993 assuming no environmental restrictions; the predicted

Figure 4–5 **Energy Production**

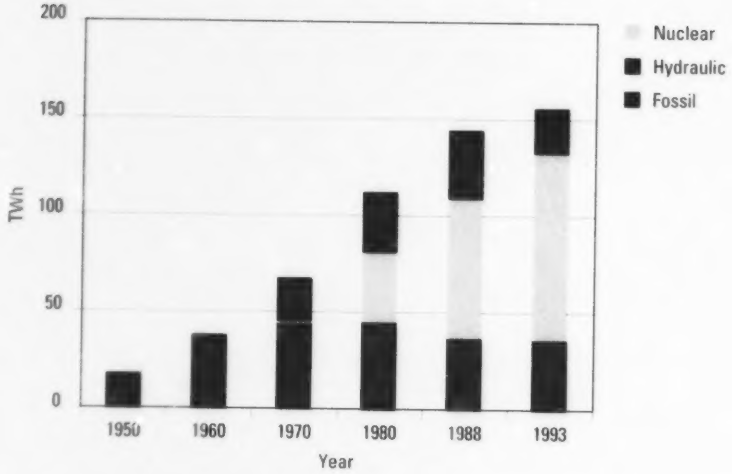
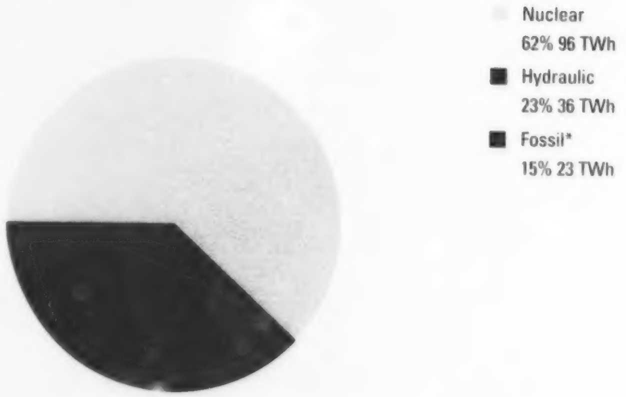


Figure 4–6 **1993 Projected Annual Energy Production by Generation Type** 155 TWh

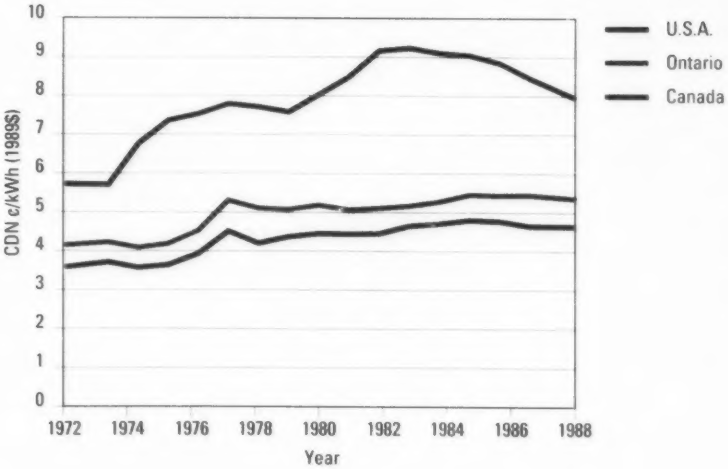


* Coal 22.9 TWh + Oil 0.1 TWh

Figure 4–7 1993 System Energy and Costs

	Capability			Deployment		
Type	Fueling Unit Energy Cost ¢/kWh	Capacity Factor (%)	Annual Energy (TWh)	Capacity Factor (%)	Energy (TWh)	Demand (%)
Hydraulic	0.1	63	36	63	36	23
Nuclear	0.5	80	99	78	96	62
Fossil – Coal	2.4	80	65	29	23	15
Fossil – Oil	5.6	80	18	0.5	0.1	
Total			218		155.1	100

Figure 4–8 **Average Electricity Retail Price To All Customers**



deployment of the generation to meet the forecast energy demand in 1993; and the variable cost of the energy from each generation type.

Hydro operates its generating capacity so that the lowest variable cost generation (hydraulic) is used to its fullest extent, the next lowest variable cost (nuclear) is used to the extent possible and the most expensive (fossil) is used only as required to meet peaks in demand. Coal is used in preference to oil to keep costs to a minimum. Purchases can be used where economic, usually to displace fossil generation.

In 1993, it is predicted that 36 TWh or 23% of the energy will be supplied from hydraulic generation, 96 TWh or 62% will be supplied from nuclear, and the remainder, 23 TWh or 15%, will be supplied from fossil generation. Eighty-five percent of the energy

Electricity is now used in many applications that used to be met by oil.

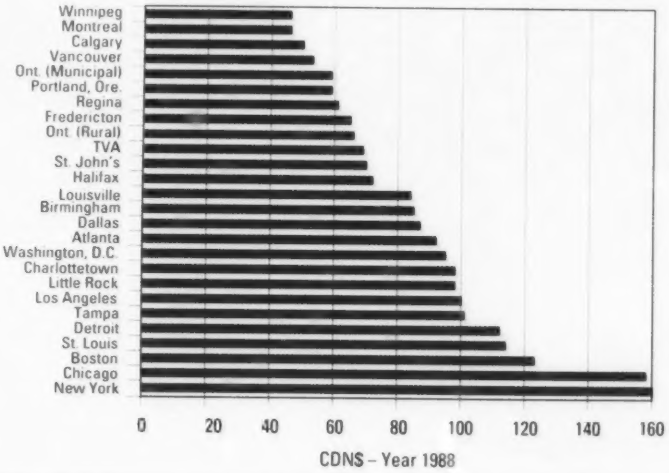
demand comes from low fuel cost generation (hydraulic and nuclear).

Operating in this manner maintains reliability and reduces cost and potential damage to the environment. No one fuel or conversion process can be counted on to do all that is expected by Ontario's electricity users in an economical manner. A mix of generation offers lower cost and flexibility.

The result of developing low cost options and using this form of system utilization is that the price of electricity to Hydro customers has remained relatively stable in real terms (Figure 4–8). Figure 4–8 also illustrates that Ontario Hydro has electricity prices somewhat higher than the Canadian average. This reinforces the importance of competitive low electricity costs in the future. The average generating cost in 1988 was 2.7 ¢/kWh (1988$). Hydro's rates are low compared to the average in the United States (Figure 4–9).

> ***Hydro operates its generating capacity so that the lowest variable cost generation (hydraulic) is used to its fullest extent, the next lowest variable cost (nuclear) is used to the extent possible and the most expensive (fossil) is used only as required to meet peaks in demand.***

Figure 4–9 **Monthly Residential Electric Bills per 1000 kWh***



*Excluding sales tax and special local charges

Natural gas can play an important role in meeting Ontario's energy needs.

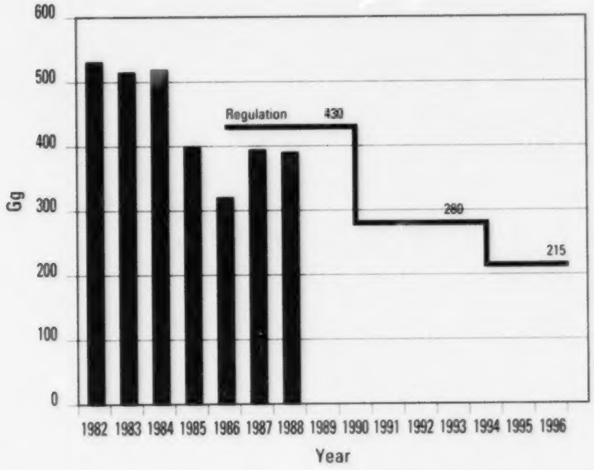


Figure 4–10 **Ontario Hydro Acid Gas Emissions and Limits**

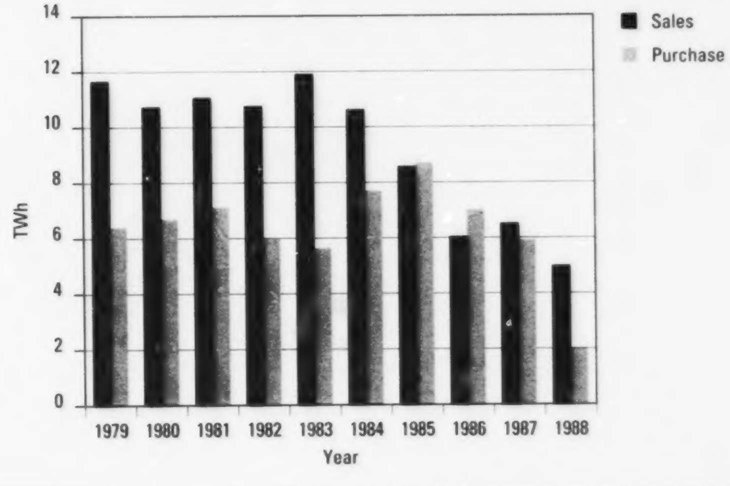


Figure 4–11 **Out-of-Province Sales and Purchases of Electricity**

Hydro's rates are low compared to the average in the United States.

ELECTRICITY DELIVERY FACILITIES

Hydro operates a transmission network or grid that carries power from Hydro's generating stations to delivery points throughout the province. The transmission component refers to the high-voltage part of the system that connects the generating stations with the major load supply points and large industrial customers. These transmission lines are illustrated in Figure 4–1.

Today's provincial transmission grid consists of integrated 500 and 230 kV networks, with regional extensions along 115 kV networks. The existing and committed transmission system consists of:

- 3,100 circuit-km of 500 kV lines;
- 13,700 circuit-km of 230 kV lines; and,
- 11,600 circuit-km of 115 kV lines.

Managing impacts on land, air, and water is a fundamental consideration in electricity production.

Environmental Concerns

Hydro's operations continue to be subject to regulations covering environmental matters.

Hydraulic generation is constrained by a number of environmental considerations including navigation, flood and erosion control, recreation and fish management. Hydro operates its hydraulic stations within these constraints and undertakes mitigating measures, such as the construction of fish ladders, where required.

Fossil generation is constrained by limits on sulphur dioxide (SO_2) and particulate emissions and limits on water temperature. In addition, by 1994, Hydro is required by legislation to reduce its total acid gas emissions by about 60% from peak levels in 1982, to a limit of 215 gigagrams (Gg) per year (Figure 4–10). Hydro is doing so by reducing the use of coal; by using fuel with lower sulphur content and by using emission control facilities.

Acid gas emission regulations currently limit the amount of energy that can be produced at existing fossil stations. Control measures such as SO_2 scrubbers will have to be fitted to existing plants if increased amounts of fossil-generated electricity are required in the 1990s and beyond.

Public concern is also leading governments to consider whether additional controls should be placed on fossil stations to control gases such as nitrogen oxides and carbon dioxide. Such controls would significantly add to the cost of new and existing fossil generation.

Disposal of nuclear waste is a matter of continuing public concern. When used fuel is taken from the reactor it is initially stored at the reactor site. Plans are being developed in co-operation with Atomic Energy of Canada Ltd., for an underground rock repository for permanent disposal of the used fuel.

The transmission system also includes transformer stations which convert lower voltage levels to higher levels, switch facilities in and out of service, provide voltage regulation and protect equipment. High transmission voltages are stepped down to lower voltages at numerous transformer points located between the grid and users of electricity.

Ontario Hydro's customers are its 850,000 rural retail customers and 316 municipal utilities which distribute electricity to three million homes and businesses throughout Ontario. Hydro also sells power to 105 industrial customers, supplied directly from the 115 and 230 kV transmission networks.

The delivery system has been designed and built for operational flexibility, cost effectiveness and reliability. Hydro staff manage the hourly and daily patterns, and often rapid fluctuations in electricity demand across the province, arising from faults, emergencies, extreme weather and other unusual conditions.

Interconnections And Purchases

The Hydro transmission grid includes interconnections with neighbouring utilities outside the province.

The interconnections with neighbouring utilities have a number of advantages for Hydro and its customers. First, they provide a backup in case of generation or transmission problems that would interfere with delivering reliable electricity to customers. Second, they allow Hydro to purchase electricity from other utilities or to sell it when it will benefit Hydro customers. Third, they help resolve certain problems such as frequency control.

Pickering generates enough electricity to supply more than 1.5 million homes.

Figure 4–12 **Fossil and Nuclear Generating Unit Retirements by 2014**

Unit Name	Capacity (MW)	40th Anniversary
Thunder Bay #1	100	2003
Lakeview #1	289	2002
Lakeview #2	289	2003
Lakeview #3	284	2005
Lakeview #4	284	2005
Lakeview #5	285	2007
Lakeview #6	285	2009
Lakeview #7	285	2009
Lakeview #8	285	2009
Lambton #1	525	2010
Lambton #2	525	2009
Lambton #3	525	2010
Lambton #4	525	2010
Pickering #1	515	2011
Pickering #2	515	2011
Pickering #3	515	2012
Pickering #4	515	2013
Nanticoke #1	542	2013
Nanticoke #2	542	2013
Nanticoke #3	542	2013
Nanticoke #4	542	2014

Out-of-province interconnections are estimated to provide Ontario Hydro with support equivalent to 700 MW of reliable capacity at the time of peak load. Firm, long-term capacity purchases are in addition to this 700 MW.

Through interconnections Ontario Hydro makes purchases and sales of electricity to reduce customer costs and improve reliability. Short-term transactions are made from hour to hour and day to day. For instance, purchases are made when the cost of purchase electricity is lower that what it would cost to produce it from Hydro's own stations. Longer term transactions depend on many factors in the Ontario Hydro and neighbouring utility systems. Transactions in recent years are shown in Figure 4–11.

At present Ontario Hydro does not have contracts for major firm sales to other utilities.

Life of Generating Facilities

About 9.0 GW of generating capacity, or 28% of existing generation, is expected to reach the end of its service life by the year 2014.

That generating capacity includes 35 hydraulic stations ranging in size from 0.8 to 76 MW and totalling 257 MW. Hydraulic stations are planned to be rehabilitated or redeveloped indefinitely to make continuing use of this renewable energy. Plans for rehabilitation of hydraulic stations are described in Chapter 10.

The following fossil and nuclear stations, totalling about 8.7 GW, are expected to be retired at the end of their 40-year service life.

Figure 4–13 **Fossil and Nuclear Retirements**

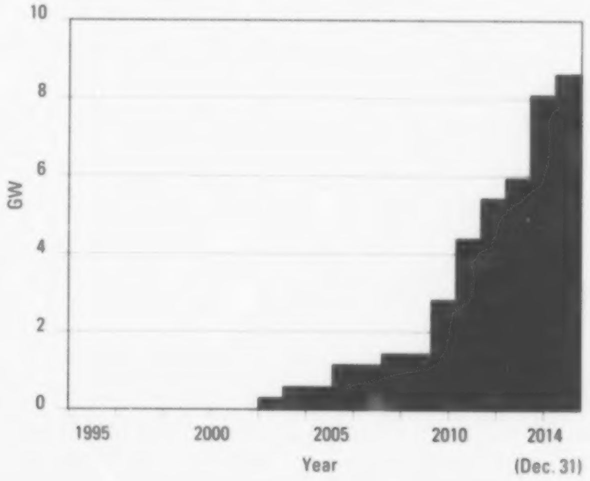


Figure 4–14 **Projected Generating Capacity of Existing System**

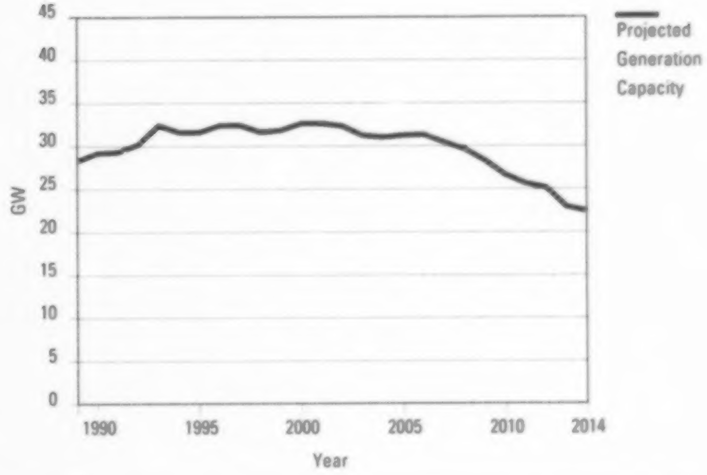
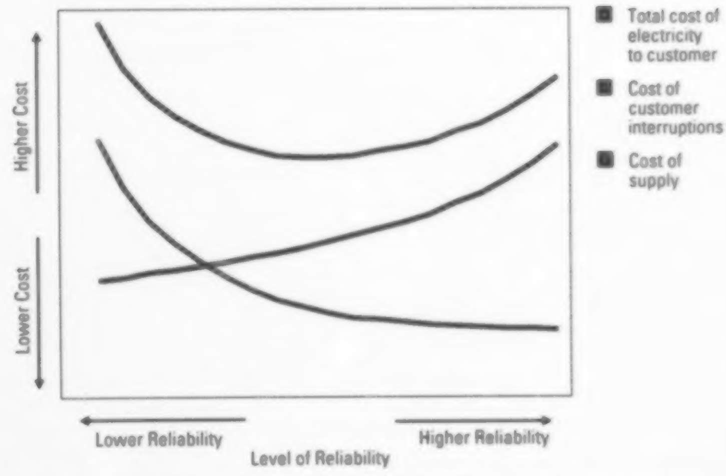


Figure 4–15 **Total Cost of Electricity**



Retirements of economically obsolete generation will reduce the existing system's capacity to meet people's electricity needs by 8.7 GW, or 28% of the existing generation, by 2014.

Fossil

• Thunder Bay Unit 1	100 MW
• Lakeview	2,286 MW
• Lambton	2,100 MW
• Nanticoke Units 1 to 4	2,168 MW

Nuclear

• Pickering A	2,060 MW

The equipment in a generating station physically deteriorates for a number of reasons. Some deterioration occurs with time, whether or not the units are operating. Other deterioration is related to the number of hours that a unit operates. Some is due to the thermal stress caused by startups and shutdowns. Generating units which operate at higher pressure and temperature to achieve higher efficiency are subject to rapid deterioration. Increasing maintenance cost as a unit gets older can contribute to economic obsolescence.

New technology resulting in higher efficiency and higher productivity can also contribute to economic obsolescence of generating units. Until 1970, the rapid increases in efficiency improvements and unit sizes resulted in many fossil-fueled units being replaced after a useful lifetime of 15 to 20 years.

Since 1970, there has been little improvement in generating station efficiency. Generally, unit sizes have not increased and so economies of scale have been minimal. As a result, most utilities in North America are expecting fossil-fueled units to have longer useful economic lifetimes.

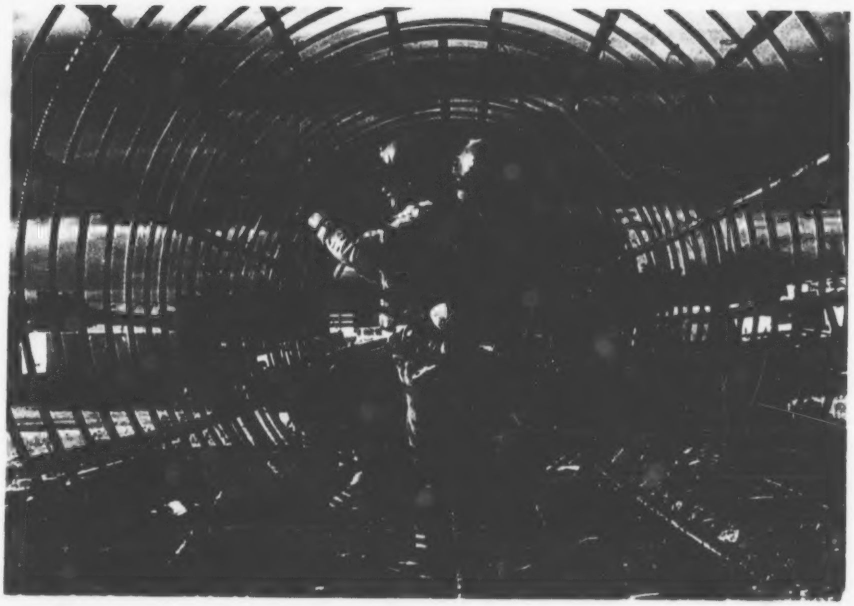
New environmental and safety regulations, which require major rehabilitation of a unit, are also factors which enter into the assessment of the economic lifetime of a generating unit.

CANDU stations operate at lower pressure and temperature than fossil stations. On the other hand, CANDU stations have deterioration resulting from the nuclear process. Increased sizes beyond 881 MW CANDU units are not contemplated for the foreseeable future.

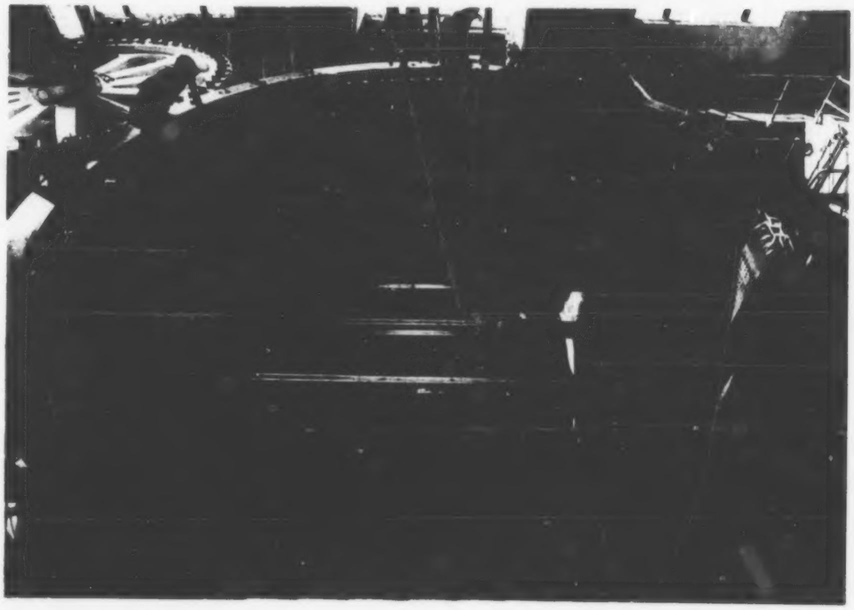
Ontario Hydro expects that the economic lifetime of its fossil and nuclear stations will be 40 years. Sensitivity studies have indicated that customer cost does not change markedly with shorter or longer lifetime. The replacement plan is, however, significantly affected by a change in lifetime of generating units.

Although this plan assumes a 40-year lifetime for fossil and nuclear units, it is expected that individual units will be replaced somewhat sooner or later than 40 years. The 40-year lifetime is judged to be a median expectation for unit retirements.

Figure 4–12 shows the fossil and nuclear unit expected retirement dates based on the 40th anniversary of the unit going in service. The amount of fossil and nuclear capacity retirements is shown in Figure 4–13.



When current construction is complete the existing system will have an installed capacity of 32.5 gigawatts.



Cameron Falls Hydro Electric Station situated on the Nipigon River.

Figure 4–16 **Reserve Margins of Various North American Utilities (%)**

Utility Name	Reserve Margin (%)
Northeast Utilities, Hartford, Conn.	24
Public Service Electric & Gas of New Jersey	22
New York Power Pool	22
Philadelphia Electric	22
Delmarva Power & Light, Delaware	22
Maritimes (New Brunswick & Nova Scotia Power)	20
Commonwealth Edison	20
Union Electric, St. Louis	18
Hydro Quebec	10
Manitoba Hydro	12

Figure 4–17 **Load Meeting Capability in 1993 (GW)**

1993 Installed Capacity	32.5
Capacity Required for a 24% Reserve Margin	6.3
Load Meeting Capability of Installed Capacity	26.2

Figure 4–18 **Load Meeting Capability of Existing Generating Capacity**

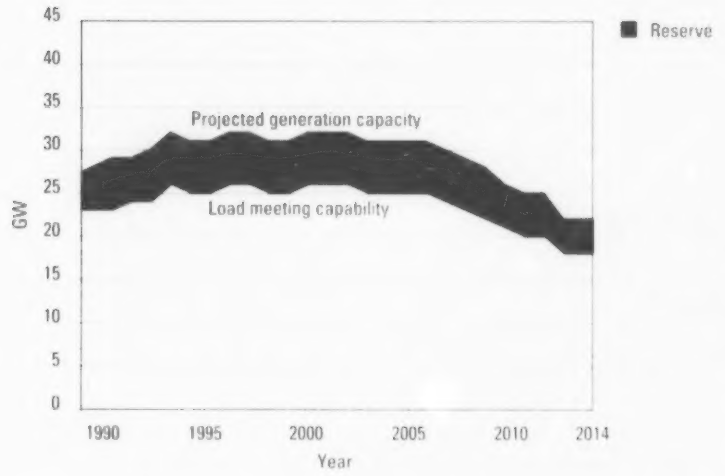


Figure 4–19 **Reference Energy Meeting Capability of Existing System**

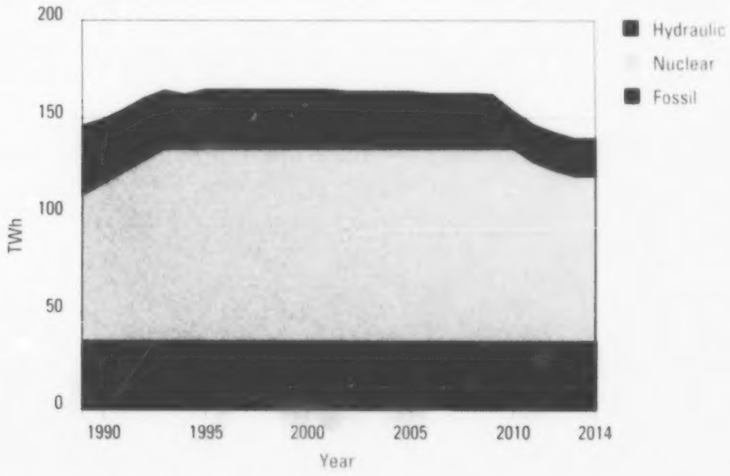


Figure 4-20 **Existing System Generation**

Generating Station	No. of Stations	No. of Units	In-Service Dates	Peak Capacity MW	Average Capacity Factor %	Typical Energy Output GWh
Hydraulic Generation						
Niagara River	6					
Sir Adam Beck-No.1		10	1922–1930	443	53	2085
Sir Adam Beck-No.2		16	1954–1958	1291	85	9941
Pumping Gen. Stn.		6	1957–1958	107	-7	-103
Ontario Power		12	1905–1913	0	44	562
DeCew Falls No.1		6	1904–1911	28	27	69
DeCew Falls No.2		2	1943–1947	136	87	1102
St. Lawrence River	1					
Robert H. Saunders		16	1958–1959	740	87	7033
Ottawa River	4					
Otto Holden		8	1952–1953	214	92	1146
Des Joachims		8	1950–1951	420	61	2178
Chenaux		8	1950–1951	118	68	725
Chats Falls (Ont.Half)		8	1931	94	46	540
Madawaska River	5					
Mountain Chute		2	1967	165	60	288
Barrett Chute		2	1942	42	19	290
Extension		2	1968	130		
Arnprior		2	1976–1977	78	20	143
Stewartville		3	1948	64	20	296
Extension		2	1969	102		
Calabogie		2	1917	3.0	63	22
Trent River	8					
Healey Falls		3	1913–1919	11.4	72	70
Ranney Falls		3	1922–1926	8.6	66	52
Meyersburg		3	1924	5.2	21	30
Sidney		4	1911	3.1	57	20
Hagues Reach		3	1925	3.4	55	19
Seymour		5	1909–1911	3.1	65	17
Frankford		4	1913	2.6	54	14
Sills Island		2	1926	1.6	48	8
Subtotal Hydraulic	24	142		4217		26547

Consequences of Reduced Reliability

If electricity demand rises to the point that interruptions are increasingly likely, the first steps taken are: to defer generation maintenance and to make emergency purchases from other utilities (if available), to cut supply to interruptible customers, to make public appeals for people to reduce their use of electricity and to reduce the system voltage. It is only after these measures that cuts are made to the firm supply of electricity to customers. The frequency and duration of interruptions may be small initially, but increase rapidly as the margin falls.

Figure 4-20 **Existing System Generation (continued)**

Generating Station	No. of Stations	No. of Units	In-Service Dates	Peak Capacity MW	Average Capacity Factor %	Typical Energy Output GWh
Montreal River	1					
Lower Notch		2	1971	260	79	414
Mattagami River	3					
Wawaitin		4	1912–1918	10.7	60	58
Sandy Falls		3	1911–1916	2.6	66	17
Lower Sturgeon		2	1923	5.9	62	41
Montreal River	2					
Indian Chute		2	1923–1924	3	73	18
Hound Chute		4	1910–1911	3.5	69	27
Matabitchuan River	1					
Matabitchuan		4	1910	10	61	57
South River	3					
Elliott Chute		1	1929	1.2	53	5
Bingham Chute		2	1923–1924	0.9	49	4
Nipissing		2	1921–1924	1.6	59	10
Sturgeon River	1					
Crystal Falls		4	1921	8.2	58	41
Wanapitei River	3					
Stinson		2	1925	5.7	44	19
Coniston		3	1905–1915	4.2	51	18
McVittie		2	1912	1.8	33	11
Nipigon River	3					
Pine Portage		4	1950–1954	112.9	63	727
Cameron Falls		7	1920–1958	75.9	74	497
Alexander		5	1930–1958	62.4	69	400
English River	3					
Ear Falls		4	1930–1948	10.8	79	111
Manitou Falls		5	1956–1958	59.5	72	354
Caribou Falls		3	1958	82	62	465
Winnipeg River	1					
Whitedog Falls		3	1958	60.7	66	385
Subtotal Hydraulic	21	68		784		3679

Retirements of economically obsolete generation units will reduce the existing system's capacity to meet people's electricity needs by 8.7 GW, or 28% of existing generation, by 2014.

Figure 4–14 indicates the projected generating capacity of the existing system from 1989 to 2014, at the time of the winter peak demand. Other than Darlington, it assumes no new generation additions. It shows the installed capacity less retirements and major outages for rehabilitation.

Reliability Reserve

People regard their electricity supply as reliable if they continuously receive all of the electricity they want. It is common practice to measure unreliability by how often the electricity is interrupted, by how long it is interrupted, and by how much electricity the customer wants that goes unserved.

In general terms, it is not possible to make an electrical system perfect or 100% reliable. This raises the fundamental question of how reliable an electrical system should be. The answer to this question is illustrated in principle in Figure 4–15. To make the electricity supply system more reliable, the cost of adding facilities to do so will increase the electricity price to the customer. On the other hand if too few facilities are installed, interruptions of electricity to the customer will result in their having to bear the cost of not having electricity available. For example, most factories would incur large costs from loss of production without continuous electricity supply. The impact of unreliability also varies from customer to customer. For example, the impact on a residential customer can be different than the impact on a factory.

Studies of how to minimize electricity supply costs and customer damage costs have led Hydro

Figure 4-20 Existing System Generation (continued)

Generating Station	No. of Stations	No. of Units	In-Service Dates	Peak Capacity MW	Average Capacity Factor %	Typical Energy Output GWh
Kaministikwia River	2					
Silver Falls		1	1959	45.5	45	190
Kakabeka Falls		4	1906–1914	17	51	148
Aguasabon River	1					
Aguasabon		2	1948	43.9	82	315
Mississippi River						
High Falls	1	3	1920	2.6	86	15
Rideau River						
Merrickville	1	2	1915–1919	0.8	68	3
Otonabee River	2					
Auburn		3	1911–1912	1.8	57	10
Lakefield		1	1928	1.7	48	8
Muskoka River	2					
Ragged Rapids		2	1938	7.5	60	42
Big Eddy		2	1941	7.1	56	39
South Muskoka	3					
South Falls		3	1916–1925	4.2	76	27
Trethewey Falls		1	1929	1.6	50	9
Hanna Chute		1	1926	1.2	88	8
Beaver River	1					
Eugenia		3	1915–1920	6.3	50	18
Severn River	1					
Big Chute		4	1911–1919	4.3	88	30
Abitibi River	2					
Abitibi Canyon		5	1933–1959	294	52	1311
Otter Rapids		4	1961–1963	178	54	688
Mattagami River	3					
Little Long		2	1963	127	18	537
Harmon		2	1965	132	49	603
Kipling		2	1966	142	47	635
Subtotal Hydraulic	19	47		1018		4636

Figure 4.20 **Existing System Generation (continued)**

Generating Station	No. of Stations	No. of Units	In-Service Dates	Peak Capacity MW	Average Capacity Factor %	Typical Energy Output GWh
Mississagi River	4					
Aubrey Falls		2	1969	158	13	165
George W. Rayner		2	1950	46	5	18
Wells		2	1970	229	18	369
Red Rock Falls		2	1960 - 1961	40	53	194
Sub Total Hydraulic	4	8		473		746
Total Hydraulic	68	265		6489		35608

Transmission networks carry electricity from Hydro's generating stations to delivery points all across the province.

to develop a reliability standard for generation of 25 system minutes per year. This means that, on the average over the long term, customers will be without electricity equivalent to 25 minutes per year of peak system demand due to inadequate generation. Additional interruptions would likely occur as a result of transmission, distribution and other problems.

Perfect reliability cannot be achieved because demand cannot be forecast perfectly and generating units are not always available for use when needed. Demand for electricity, for example, can vary as a result of unusual weather or unexpected economic growth.

No type of generation – hydraulic, fossil or nuclear – is continuously in service. All types of generation have problems which force generating units out of service. The extra generating capacity to accommodate these and other factors is called the reserve capacity.

Large generating units tend to have lower unit energy costs and somewhat lower reliability. Planning seeks to minimize the customer total cost by seeking an optimum unit size and appropriate system reserve margin.[†]

The amount of reserve margin needed to meet the 25 system minute reliability criterion for Ontario Hydro is typically 22 to 24% of the customer load.

$$\text{reserve margin} = \frac{\text{reserve capacity}}{\text{customer load}} \times 100$$

A number of utilities in North America are beginning to express the reserve margin in terms of a capacity margin[†] using the following formula:

$$\text{capacity margin} = \frac{\text{reserve capacity}}{\text{total capacity}} \times 100$$

Figure 4-20 **Existing System Generation (continued)**

Generating Station	No. of Stations	No. of Units	In-Service Dates	Peak Capacity MW	Average Capacity Factor %	Typical Energy Output GWh
Fossil Generation						
Coal-Fueled	5					
Lakeview		8	1962–1969	2286	65	1082
Lambton		4	1969–1970	2100	72	5381
Nanticoke		8	1973–1978	4336	78	15443
Thunder Bay Unit 1		1	1963	100	86	27
Units 2 & 3		2	1981–1982	320	85	733
Atikokan		1	1984	215	84	539
Subtotal Coal (CSC)	5	24				
Residual Oil-Fueled (CSC)	1					
Lennox		4	1976–1977	2232	87	80
Subtotal (CSC)	6	28		11589		23285
Oil-Fueled CTU	9					
Lakeview		3	1967	23	90	
Lambton		3	1967	23	90	
Nanticoke		3	1971	23	90	
Lennox		2	1975	5	90	
Bruce "A"		2	1974–1976	33	90	
Bruce Services		3	1976	33	90	
Bruce "B"		2	1982–1984	33	90	
Darlington		2	1987	52	90	
Thunder Bay		2	1969	33	90	
Subtotal Oil CTU	9	22		258		13
Nuclear Generation						
Uranium-Fueled (CANDU)	5					
Pickering A		4	1971–1973	2060	86	15257
Bruce A		4	1976–1978	3076	58	15435
Pickering B		4	1983–1985	2064	85	15103
Bruce B		4	1984–1987	3440	83	24711
Darlington		4	1989–1992	3524	85	25885
Total Nuclear	5	20		14164		96391
Total System	79*	313*		32500**		

** Excludes CTU's   ** Includes CTU's*

Under this formula, the typical capacity margin for utilities range from 16 to 20%.

Interruptions on the system of one utility can cause difficulty for other interconnected utilities. Consequently, North American utilities meet periodically to review each other's reliability situation in a forum known as the North American Electric Reliability Council (NERC). NERC provides reliability guidelines to utilities.

A target reserve margin of 24% has been used for this report. In the median forecast cases, it will vary from about 22 to 24% because of changes in demand and supply factors from year to year.

For comparison, the reliability reserve requirements of some other utilities are provided in Figure 4–16.

This comparison must be treated with some care because the margin definition and calculation can vary among utilities. Utilities such as Quebec and Manitoba Hydro, use mostly hydraulic generation, and have good water storage, can work with lower margins because of the high reliability of hydraulic units. The other utilities shown have reserve margins between 18 and 24%. Each utility develops a reserve margin to optimize its own particular circumstances. For instance, Commonwealth Edison relies on its strong interconnection facilities.

Future Load Meeting Capability of the Existing System

The effect of allowing for a 24 percent reserve margin is illustrated in Figure 4–17.

Hydro's generating facilities will have a total installed capacity of about 32.5 GW by 1993, when Darlington is completed. With a reserve of 24% of customer load, the required reserve for Hydro's 32.5 GW generating system is 6.3 GW.

The difference between these two figures is 26.2 GW. This is known as the load-meeting capability of the existing system, and is the peak demand that can be reliably supplied to the customer by the system, including transmission delivery losses.

As shown in Figure 4–18, the projected load meeting capability of the existing system increases as Darlington comes into service, then stays level to 2006, and then steadily declines as major generating stations reach the end of their service lives.

Future Energy Meeting Capability of the System

Hydraulic and nuclear generation are types already used as much as possible because they are the generation with the lowest variable costs. Fossil generation is used only as required because it is the most expensive. More use could be made of fossil generation, at a price, if the demand were to occur at off-peak periods and if additional environmental controls were fitted.

The practical energy meeting capability of the existing system is limited by the amount of acid gas controls fitted to the coal-fueled units.

The acid gas emission limit drops from 430 to 280 Gg per year in 1990 and to 215 Gg per year in 1994. This restricts fossil fueled energy production capability. Installation of flue gas conditioners starting in 1990, and scrubbers starting in 1994, will restore some of that production capability, but there will be a net reduction of about 6 TWh.

As the Darlington units come into service the nuclear capability increases by about 24 TWh. An illustration of the system energy production capability with environmental restrictions is shown in Figure 4–19.

The system energy production of the system in 1989, with environmental restrictions, is about 150 TWh, by the mid-1990s the capability stabilizes at about 165 TWh per year. Beyond 2002, the capability declines because of the retirement of generating units. About 9 TWh per year of the capability is used as a margin for contingencies.

New environmental regulations, now being discussed, could lead to further reductions in fossil energy production capability. ■

5 REQUIREMENT FOR DEMAND/SUPPLY OPTIONS

This chapter establishes the requirement for new demand and supply options to 2014 by comparing the full bandwidth forecast of basic electricity demand (Chapter 3) with the load meeting capability of the existing system (Chapter 4).

This comparison shows that timely decisions on demand/supply options must be made if Ontario's electricity customers are to continue to enjoy reliable, low-cost electricity service in the future.

PEAK POWER REQUIREMENTS

Median Forecast: New Options Required by 1993

Figure 5–1 shows the median Basic Load Forecast for peak power, and the load-meeting capability of the existing system for the period to 2014. The year in which demand exceeds existing capability is called the need date for new options. The need date for the median forecast is 1993. Between 1990 and 1993, the demand and supply remain reasonably balanced as the Darlington station comes into service.

For long-term planning, the important factor is the increasing divergence between forecast demand and load-meeting capability to the year 2000 and beyond.

The options required after the need date may come in the form of reducing the growth in demand or in the form of new sources of supply to increase load-meeting capability. The width of the gap in a particular year indicates the amount of demand to be met by additional demand/supply options.

It should be noted that demand continues to increase from 1993 to 2014, and that capability declines significantly due to retirements in the period 2006 to 2014. The requirement for new demand/supply options increases to 21 GW by the year 2014. This is close to the current peak power demand.

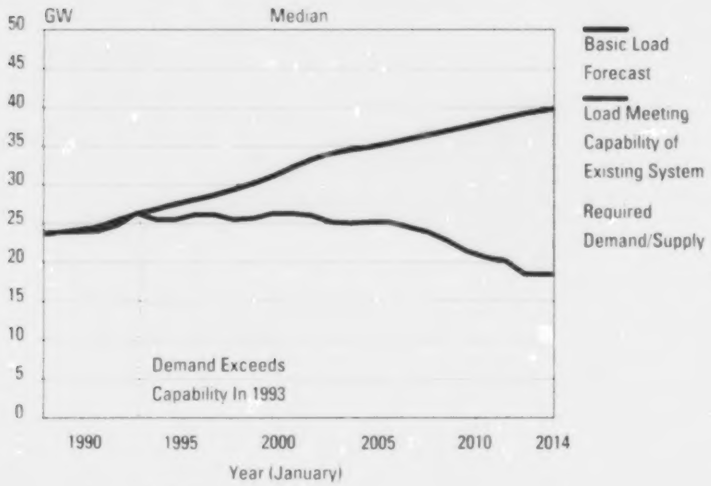
Upper Forecast: New Options Required Now

It is important to remember that the Basic Load Forecast incorporates a bandwidth approach, reflecting uncertainty about the growth of the province's future needs for electricity service. This bandwidth is identified in Chapter 3.

Figure 5–2 shows the upper Basic Load Forecast and the load meeting capability of the existing system. If load growth continues on the upper path without demand/supply options being implemented, the reliability reserve will decline.

Given the lead time† for new options, Ontario Hydro is preparing the R.L. Hearn units as a contingency measure to help meet

Figure 5-1 **Required Demand/Supply – Peak Power Demand**



this potential requirement. This is a short-term expedient, given that this capacity is old, inefficient, and expensive. The requirement for new demand/supply options increases to 26 GW by the year 2014.

Faced with increasing reqirements, timely actions are necessary to address the risk of deteriorating service.

Lower Forecast: New Options Required by 2000

There is a 50 per cent chance that the load will be less than the median, and a 10 per cent chance that the load will be less than the lower forecast. As illustrated in Figure 5–3, there is still a requirement for new options for the lower forecast commencing in the year 2000. The requirement by 2014 is 15 GW, of which a major part is due to retirement of existing fossil and nuclear stations.

Figure 5–2 **Required Demand/Supply – Peak Power Demand**

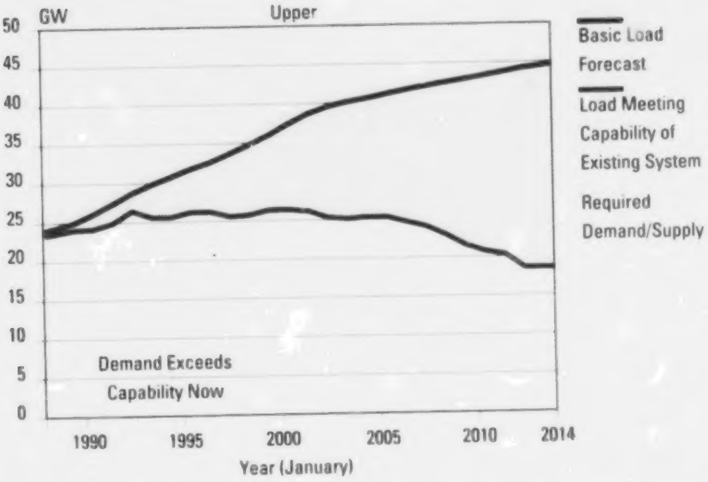
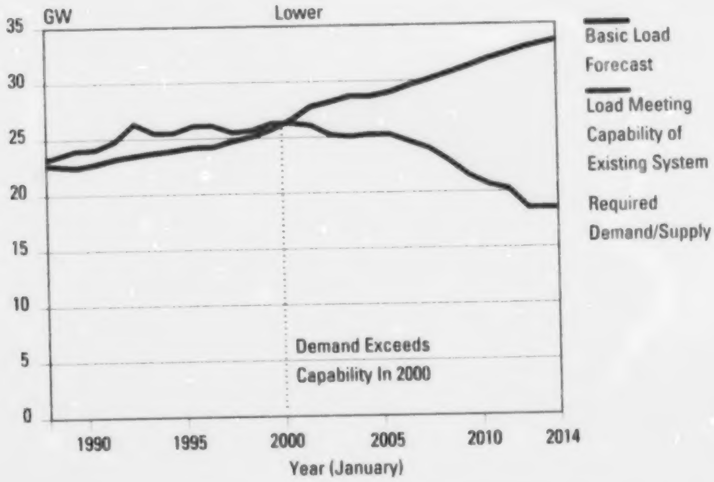


Figure 5–3 **Required Demand/Supply – Peak Power Demand**



THE NEED TO MAINTAIN RELIABILITY

The Projected Shortfall Would Lead to Unreliability

Without actions to increase supply and reduce demand when demand begins to exceed capability, the reliability of service would decline. Although the deterioration would not be noticeable immediately, it would quickly worsen as the gap between demand and capability widens.

In the median forecast, the reliability reserve would likely slip to 15 per cent by 1995 or 1996, compared to the target of 24 percent. Unsupplied customer energy† would likely increase to many times the acceptable standard. With a planning reserve margin of only 15 per cent, unsupplied customer energy would average about 160 system minutes per year, compared to the reliability criterion of 25 system minutes† per year.

Faced with increasing requirements, timely actions are necessary to address the risk of deteriorating service.

Summary: Need Dates and Requirements

Figure 5–4 tabulates the requirements for new demand/supply options. The requirement for additional demand/supply by 2014 ranges between 15 GW and 26 GW. The load-meeting capability of the existing system in 1988 was 23 GW.

Figure 5–5 shows the requirements for demand/supply in gigawatts by year for the three forecast bandwidths.

Figure 5.4 **Requirements* for New Demand/Supply Options (GW)**

January of Year	Lower Forecast	Median Forecast	Upper Forecast
1990	0	0	0.9
1995	0	2.0	5.2
2000	0	5.0	9.9
2005	3.4	9.7	15.4
2010	9.8	16.0	21.4
2014	15.0	21.3	26.2

* Load-meeting capability

Figure 5-5 **Required Demand/Supply – Peak Power Demand**

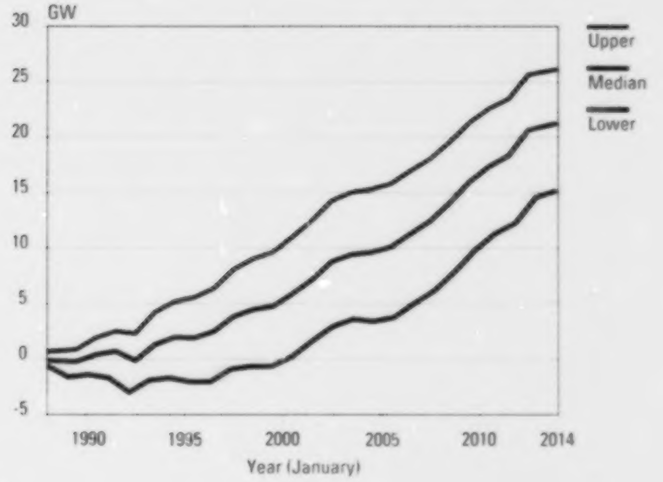
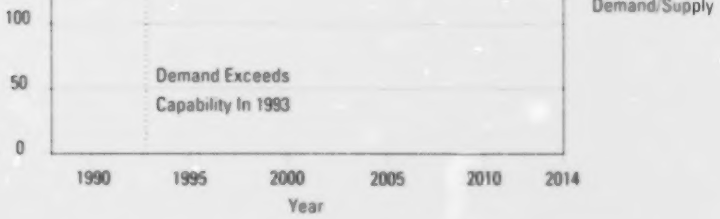


Figure 5-6 **Required Demand/Supply* – Annual Energy Demand**



*To be met by new demand/supply options and redeployment of the existing system

Energy Requirements

Energy and capacity requirements are both important in planning. Both have major implications. Planning to meet the capacity requirements has major implications for preserving reliability, while meeting energy requirements has major implications for maintaining low costs and mitigating environmental impacts.

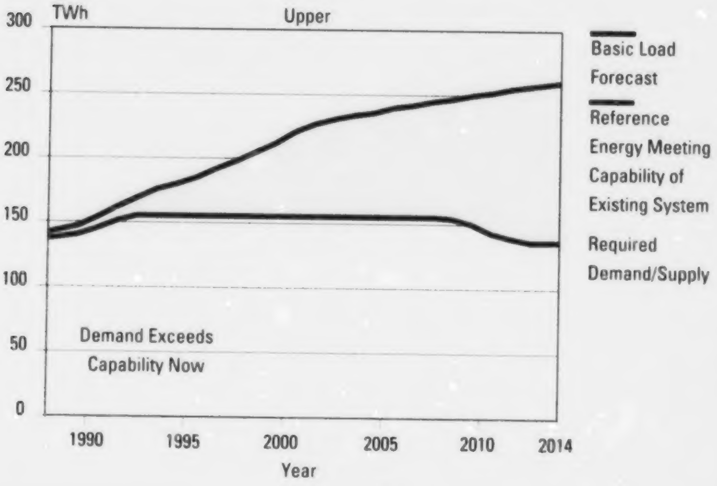
Figures 5–6, 5–7, and 5–8 show the energy requirements for the median, upper, and lower load forecasts. The top line illustrates the Basic Load Forecast for energy and the lower line shows the energy meeting capability of the existing system. The figures illustrate the required energy to be met by new demand/supply options and redeployment of the existing system.

For example, existing coal-fueled generating stations can be operated at higher capacity factors to meet part of the future energy requirements. Such redevelopment requires retrofit of scrubbers to reduce the acid gas emissions.

Figure 5–9 lists the energy requirements to be met by new demand/supply options or redeployment of the existing system. By 2014, the annual energy requirement grows to an additional 98 terawatt hours for the median forecast. An increase of about 75 percent over the energy demand in 1988. Increased energy requirements tend to increase environmental impacts unless low-impact options are selected and committed on a timely basis.

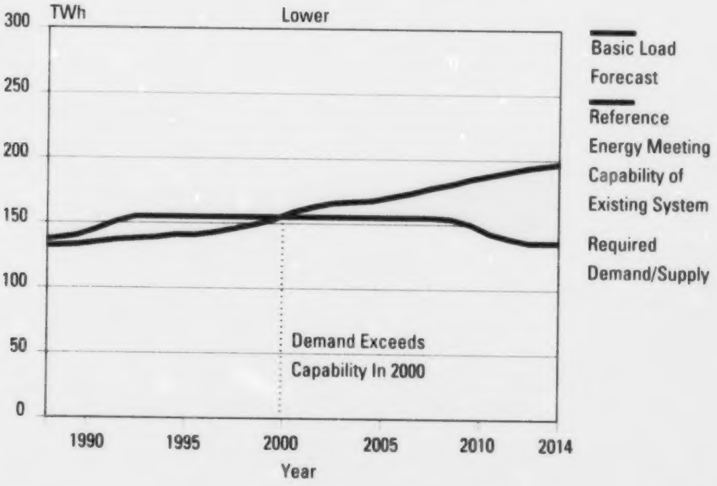
Figure 5–10 plots the energy requirements

Figure 5–7 **Required Demand/Supply* – Annual Energy Demand**



*To be met by new demand/supply options and redeployment of the existing system.

Figure 5–8 **Required Demand/Supply* – Annual Energy Demand**

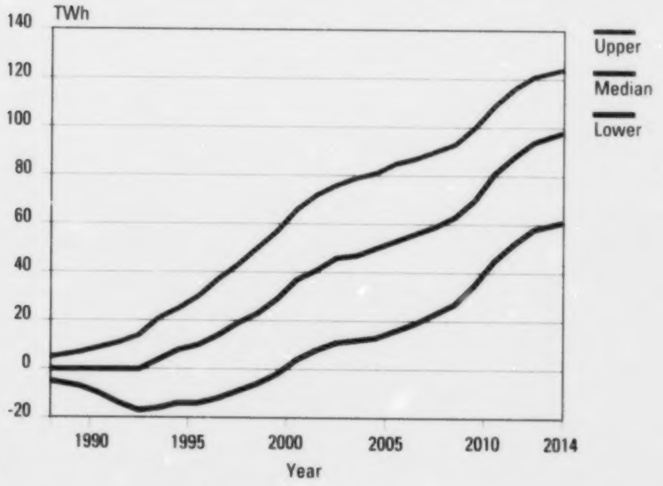


*To be met by new demand/supply options and redeployment of the existing system.

Figure 5–9 **Future Energy Requirements (TWh)**

Year	Lower Forecast	Median Forecast	Upper Forecast
1990	0	0	7
1995	0	8	25
2000	0	29	57
2005	13	50	81
2010	35	70	100
2014	61	98	124

Figure 5–10 **Required Demand/Supply* – Annual Energy Demand**



*To be met by new demand/supply options and redeployment of the existing system.

for new demand/supply options.

Preparations for New Demand/Supply Options Should Start Immediately

This chapter shows early need dates and large requirements for new demand/supply options to maintain customer reliability, low customer costs, and to protect the environment.

There are options with short lead times, like some demand management programs, non-utility generation, and combustion turbines. Hydro is counting on these to help meet customer needs in the 1990s.

Ontario Hydro's planning must recognize that it takes time for demand management programs to take effect, and for new low cost supply facilities to be designed, approved, and constructed. Because of these long lead times, it is urgent to start preparations immediately. ●

Chapter 11
Requirement for New Supply

Chapter 12
The Hydraulic Plan

Chapter 13
Requirement for Major Supply

Chapter 14
Major Supply Options

Chapter 15
Major Supply Plans

Chapter 16
Avoided Cost Determination

Chapter 17
Demand/Supply Plans

Chapter 18
Action Plans

6 COSTING CONCEPTS AND AVOIDED COSTS

In Chapter 5, the requirement for additional demand and supply options is established for each year during the 25 year planning period. Cost is one of the primary criteria in developing the best integrated demand/supply plan to meet these future requirements.

This Chapter focusses on the general costing concepts that Hydro uses to help make planning decisions; and, one particular application called "avoided cost". Avoided cost is defined as the supply costs which are avoided when any demand or supply option is substituted for an equivalent part of a demand/supply plan.

Those interested in avoided costs approach the issue from many different perspectives ranging from profit motivation to low costs. Over the years a variety of methods and assumptions to calculate avoided costs have been adopted in a number of jurisdictions in the U.S. These differences add to the controversy surrounding the subject.

Hydro has the responsibility to act in the best interest of its customers. It is important that costing concepts be fundamentally sound and applied consistently so as to be fair to all parties.

An example of fairness is the cost estimates for generation options owned and operated by Ontario Hydro. These estimates must be comprehensive and realistic with all direct and indirect costs included. Similarly, Ontario Hydro's estimates for options managed by other parties must also be comprehensive, realistic and include all direct and indirect costs.

Recognizing the importance of this subject and its controversial nature, Ontario Hydro declared before the Select Committee on Energy of the Ontario Legislature its intended policy to have periodic public review of costing concepts and avoided cost determinations. This plan report and, in particular, Chapters 6 and 16 provide a basis for such a public review.

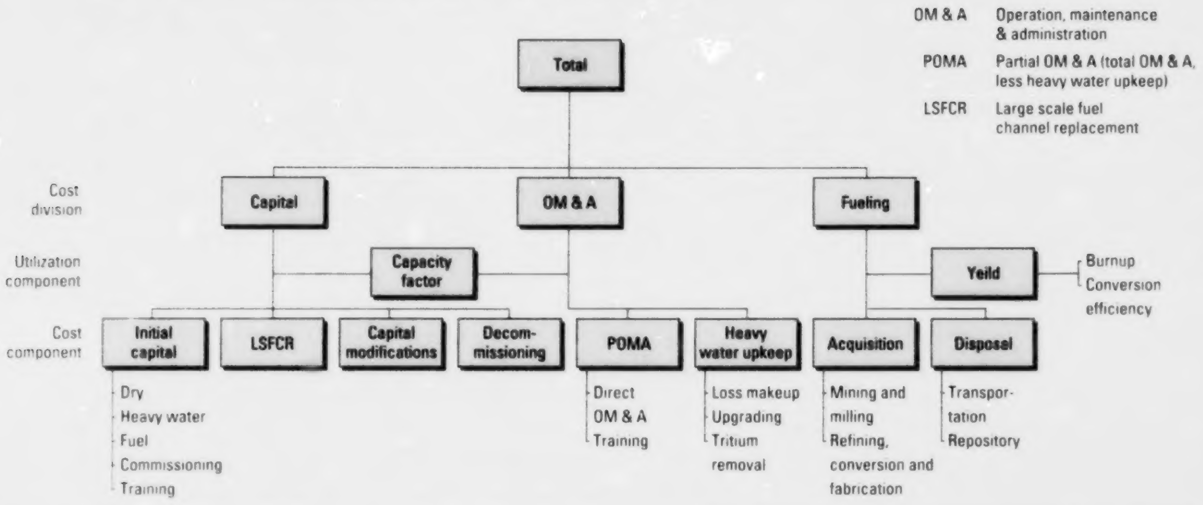
The Minister of Energy announced on November 6, 1989 that the review of this plan would take place before the Environmental Assessment Board and that the review would include a consideration of social and environmental costs. The issues surrounding social and environmental costs and benefits are discussed in this chapter.

Ontario's current electricity needs are met through a variety of demand and supply options. Future needs will also be met through a mix of these options.

In making decisions about the options to be employed, Hydro must be able to evaluate them from a variety of perspectives. While many criteria will be used, one of the primary criteria is an evaluation based on cost. Hydro wants to know how different options and combinations of options will affect customers' electricity costs over the long term.

No two options are alike. Some supply options will be more costly to build than others. Some options will require higher expenditures for environmental control than others. Some

Figure 6-1 **Nuclear Project Cost Model Showing Full Life Cycle Costs**


OM & A Operation, maintenance & administration
POMA Partial OM & A (total OM & A, less heavy water upkeep)
LSFCR Large scale fuel channel replacement
Total
Cost division
Capital
OM & A
Fueling
Utilization component
Capacity factor
Yeild
Burnup
Conversion efficiency
Cost component
Initial capital
LSFCR
Capital modifications
Decom-missioning
POMA
Heavy water upkeep
Acquisition
Disposal
Dry
Heavy water
Fuel
Commissioning
Training
Direct
OM & A
Training
Loss makeup
Upgrading
Tritium removal
Mining and milling
Refining, conversion and fabrication
Transportation
Repository

options will last decades, while others will only last a few years. In evaluating the costs, Ontario Hydro takes into account these different characteristics.

Different concepts and methods for evaluating costs have been devised which reflect different characteristics and give different perspectives on the costs. For example, accounting costs have to be examined to assess rate impacts, while incremental costs are used for economic analysis. This chapter covers the different concepts and the perspectives they provide. The methods of economics are applied consistently to all demand/supply options.

The concept of avoided cost is particularly useful in evaluating demand management, non-utility generation and hydraulic generation costs. It draws on the concepts of economic appraisal and is described later in this chapter.

The costing concepts used by Hydro are used by other utilities for similar decision making purposes.

The following general costing concepts are discussed in this Chapter:

- cost measurement – constant and inflated dollars;
- comprehensive life cycle costs† – all options;
- Total Customer Cost† concept;
- Accounting Cost concept;
- Direct and Allocated costs† (D&A) vs System Expansion Costs† (SE);
- Present Value† methodology (PV);
- Levelized Unit Energy Cost (LUEC)†;
- allocation of costs to plan period;
- long run supply costs;
- uncertainty – expected costs; and,
- social and environmental costs and benefits.

Avoided costs are discussed under the following topics:

- avoided cost-concept and application;
- establishing avoided costs;
- determination of avoided costs – NUGs and demand management; and,
- current estimates of avoided costs.

High efficiency lighting in commercial and industrial buildings can save money for both the customer and the utility.

GENERAL COSTING CONCEPTS

Cost Measurement – Constant and Escalated Dollars

The first factor in dealing with forecasts of costs is inflation.

In forecasting the price of a particular commodity, allowance is made for market factors which may cause costs to change faster or slower than inflation.

Hydro expresses forecast costs in both constant and escalated dollars[†]. Escalated dollars are the actual dollars spent in any future year. Sometimes they are referred to as dollars of the year. Escalated dollars include the effect of inflation. To relate escalated dollars to current purchasing power, inflation has to be removed. For example, $1,000 (escalated) spent in 2000 would only buy the equivalent of spending $600 in 1989.

Costs which exclude inflation, are known as constant, or real dollars. Using constant dollars makes it clear whether costs are forecast to rise faster or slower than general inflation. Constant dollars allow comparison with today's values and purchasing power.

$$\text{Real or constant dollars} = \frac{\text{Escalated dollars}}{\text{Inflation Index}}$$

Real costs can be expressed in constant dollars of any particular year. In this document constant dollars of 1989 are used.

Money will not be worth what it is today

Inflation is usually measured in terms of the Consumer Price Index. The table below is the forecast of the Consumer Price Index used in these studies. It shows the dollars that will have to be spent in the future to buy what $1 will purchase today.

Year	Inflation Index	Year	Inflation Index
1989	1.00	2002	1.86
1990	1.04	2003	1.97
1991	1.09	2004	2.08
1992	1.14	2005	2.19
1993	1.20	2006	2.30
1994	1.25	2007	2.41
1995	1.31	2008	2.53
1996	1.38	2009	2.66
1997	1.45	2010	2.79
1998	1.52	2011	2.93
1999	1.60	2012	3.08
2000	1.68	2013	3.23
2001	1.77	2014	3.39

Comprehensive Life Cycle Costs

One principle that is crucial in estimating costs for the purpose of demand/supply planning is to include all relevant cost components for an option from its acquisition, through its operating life, to the post operation, decommissioning and dismantlement.

Life Cycle Costs = Acquisition + Operation + Post-Operation

The acquisition costs include all the costs associated with the initial design, site purchase and construction. The operation phase costs include those for the operation, maintenance, and fuelling of an option, as well as the overheads, that are associated with carrying out these activities. Operation (excluding fuel), maintenance and administration are often grouped together and referred to collectively as OM&A. Post operation costs include decommissioning and used fuel disposal costs.

Another way of dividing the costs is into capital, OM&A, and fuelling. A display of all the life cycle components, divided in this way, for a nuclear station is shown in Figure 6–1. This cost model was reviewed and validated by the Ontario Nuclear Cost Inquiry. A cost estimate was made for each element in the figure.

Figure 6–2 illustrates an example of the expenditures over the full life cycle of a nuclear station with the first unit planned for 2002. All costs are in constant 1989 dollars. It shows that capital costs occur primarily in the acquisition phase, although there are substantial capital costs in the operating and post operation phases for retubing and decommissioning.

Similar cost models were developed for the Thermal Cost Review. These models are adjusted to reflect the specific elements of alternative options, and include explicit recognition of the costs to remove sulphur dioxide and nitrogen oxides.

For NUGs the costs included are those specified in the contract and other costs such as Hydro's administration costs.

The life cycle cost of a demand management option includes the incremental equipment and the OM&A costs associated with the option.

Full life cycle costs are used by Hydro to evaluate the costs of different options and plans. It is important that the life cycle cost estimates be comprehensive and realistic.

Cost Component Accuracy

For the nuclear and fossil options, estimates of the accuracy of the individual components are combined to estimate the accuracy of the total.

The uncertainties included in the analysis include considerations of possible changes in wages, working conditions, technological developments, and social and environmental requirements.

The development of the estimates uses probability analysis to the degree possible. When data is limited, reliance on expert judgement is necessary.

Total Customer Costs

The Total Customer Cost concept is used to evaluate demand management options. An electricity efficiency option affects the cost of the customer's equipment and also affects supply costs.

Both components of the cost are ultimately paid for by all customers through electricity rates. Therefore a costing concept used by Ontario Hydro is Total Customer Cost.

Figure 6–2 **Life Cycle Cost of a Nuclear Plant** Total

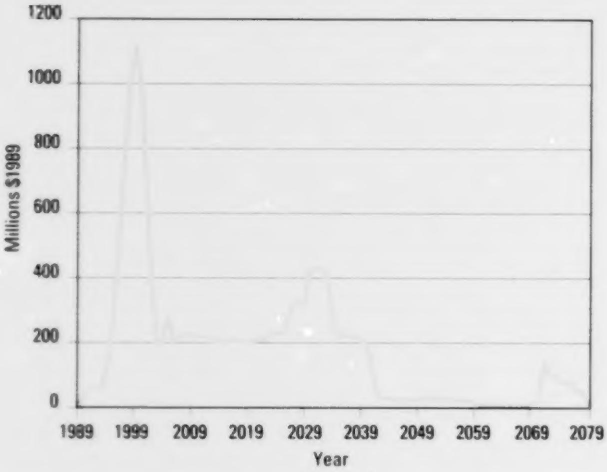


Figure 6–2 **Life Cycle Cost of a Nuclear Plant** OM&A

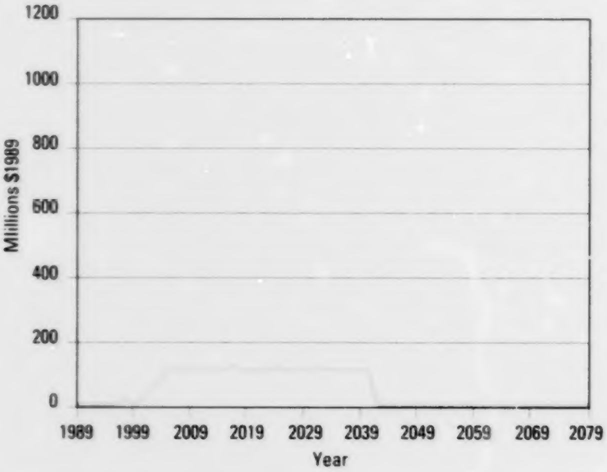


Figure 6–2 **Life Cycle Cost of a Nuclear Plant** Capital

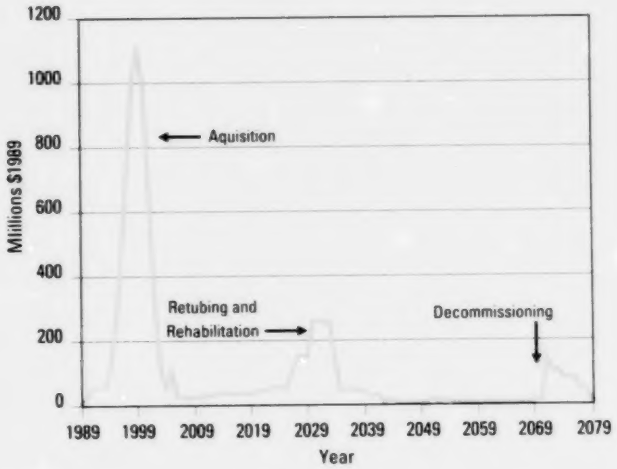
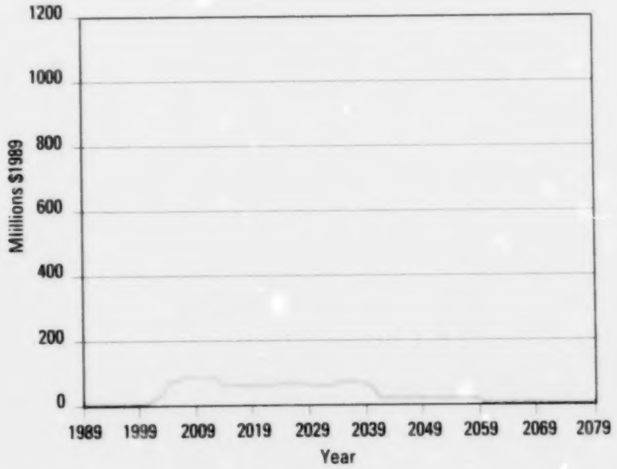


Figure 6–2 **Life Cycle Cost of a Nuclear Plant** Fueling



Acquisition	to 2002
Operation	2002 – 2042
Post Operation	2043 – 2083

The Total Customer Costs include, on the production side, all the costs involved in building the electricity system, the fuel and operating resources. Included on the utilization side, are all the costs incurred by the end user in obtaining the service required – heating, lighting, motor power, etc. Figure 6–3 illustrates the concept of Total Customer Cost.

To determine whether or not an insulation program for electrically heated houses is an economic option, a comparison is done. Without an insulation program, the Total Customer Cost is the cost of generating, transmitting and distributing the electricity needed to heat the house. With the insulation program the Total Customer Cost includes the cost of insulation and the cost of supplying a lesser quantity of electricity. The lowest Total Customer Cost is economically preferred.

Because incentives and changes in revenue are transfers of money between Hydro and its customers, they do not affect the total of the customers' and Hydro's costs. However, in order to be acceptable, the cost to the Hydro family of an incentive program must be equal to or less than the avoided cost of the energy saved.

The Total Customer Cost concept is important for utilities like Ontario Hydro because it helps to establish the economic potential of various demand management options.

Accounting Costs

The price customers pay for electricity is based on accounting costs.

The purpose of accounting costs is to ensure the proper allocation and recovery of the costs incurred. Underlying the determination of accounting costs are the principles of fairness and the matching of costs and benefits to customers. These principles also require the proper allocation of costs between current and future customers.

Customers pay for a facility only while they are receiving a benefit from it. Customers therefore do not pay for it during construction or after it has reached the end of its useful lifetime. Because of this, all costs no matter when incurred, are recovered through electricity rates during the operating life of the facility.

Figure 6–4 illustrates the full life cycle costs of a nuclear station and their allocation to the operating phase. Costs incurred prior to the operating phase, such as interest during construction, are accumulated and incorporated into the station's capital costs. Capital costs are allocated over the operating phase through straight line depreciation. Provision is made during the operating phase for costs that will be incurred after the operating phase. This concept of allocating all life cycle costs to the operating phase of the project is also used in various decision making cost concepts such as levelization and avoided costs which are explained later.

Accounting costs are most useful when applied to the entire Hydro system with all its components. Customers do not pay separately for components like a transmission line or a generating station. However, it is instructive to apply those accounting principles to a single component, like a generating station. Since projects are of various sizes, it is useful to express the cost per unit of electricity produced (dividing the cost in a year by the annual electricity production). This is known as the Accounting Unit Energy Cost (AUEC). The AUEC is a representation of the costs Ontario Hydro customers will pay through rates in each year of the option's lifetime. The AUEC includes the effects of all of the option's life cycle costs.

Figure 6–3 **Example of Total Customer Cost**

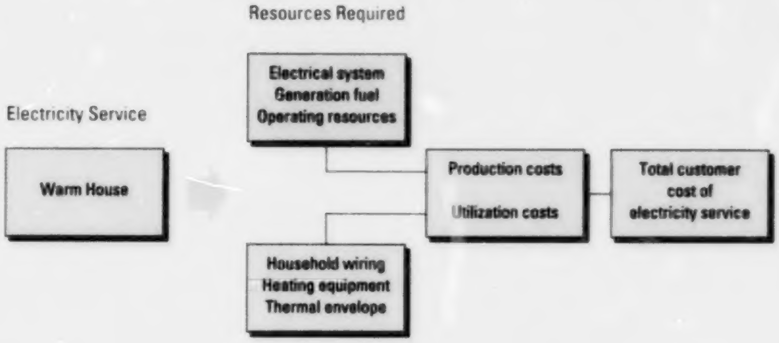

Resources Required
Electricity Service
Electrical system
Generation fuel
Operating resources
Warm House
Production costs
Utilization costs
Total customer cost of electricity service
Household wiring
Heating equipment
Thermal envelope

Figure 6–4 **Full Life Cycle Costs Recovered from Customers during Operations**

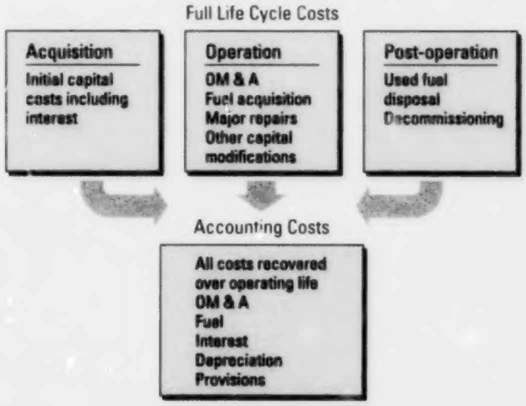
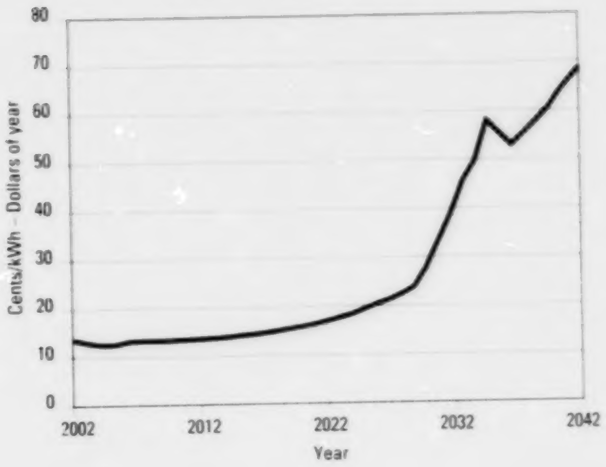
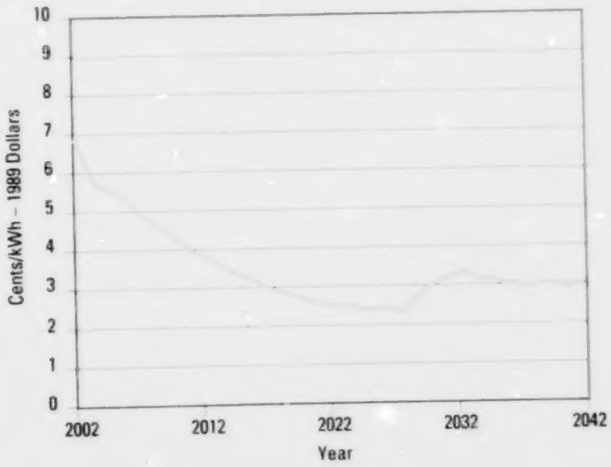

Full Life Cycle Costs
Acquisition
Initial capital costs including interest
Operation
OM & A
Fuel acquisition
Major repairs
Other capital modifications
Post-operation
Used fuel disposal
Decommissioning
Accounting Costs
All costs recovered over operating life
OM & A
Fuel
Interest
Depreciation
Provisions

Figure 6-5 **Accounting Unit Energy Cost* of a Nuclear Station in Escalated Dollars**



*Direct and allocated costs for existing site

Figure 6-6 **Accounting Unit Energy Cost* of a Nuclear Station in 1989 Dollars**



*Direct and allocated costs for existing site

When expressed in escalated dollars, the AUEC generally shows an upward trend with time as some of its components are influenced by inflation. This is shown for a nuclear station in Figure 6–5. Figure 6–6 shows the same AUEC expressed in constant 1989 dollars. In this case the AUEC in the first year is the highest, it declines to half this initial value in about ten years, and declines further for most of the life of the station. The increase in AUEC around 2030 is due to the planned retubing and major rehabilitation of the reactors.

AUECs are primarily used to indicate how various options will affect customer rates. But when comparing the corporate financial impacts of plans, full simulations of the whole system are carried out to determine electricity prices, borrowing levels, and various other financial indicators, all of which are considered in decision making.

Direct and Allocated Costs vs System Expansion Costs

In the development and implementation of options and plans, there are costs that are clearly identified as direct costs of each project and common costs that must be shared amongst several projects. In accounting for costs it is clear that there must be a comprehensive method of allocating costs so that they can be recovered. However, economic analysis is concerned not with the recovery of costs but with incremental costs. Most businesses including Ontario Hydro distinguish between these two. Accounting costs are done on a Direct & Allocated (D&A) basis. Economic analysis is done on a System Expansion (SE) basis.

For instance, there is an integrated program of producing, up-grading and de-tritiating heavy water for Ontario Hydro's nuclear program. The costs of this program must be shared

Planning must recognize inflation. What cost $1.00 in 1989 will cost $1.68 in the year 2000.

between existing and future nuclear stations, and between today's and future customers. A cost estimate which includes a full share of common costs is called the "direct and allocated cost."

For such programs Hydro has already spent money on facilities which will be used for all stations, old and new. These facilities may have to be used harder in the future to serve additional stations, at extra expense; but no further capital expenditures will be required. In such cases the incremental cost of a new station will be different from the direct and allocated cost of the shared program. Economic evaluations on expanding the system must be based on the incremental costs. Therefore, a separate cost estimate is prepared for "system expansion" purposes and this includes only the direct costs and the incremental costs of shared programs. It excludes sunk costs or fixed & committed costs.

Direct & Allocated = Direct + Part of (Sunk + Committed + Incremental)

System Expansion = Direct + Incremental

The SE cost of a new nuclear station is about 85% of the D&A cost. Most components differ only slightly, but the SE and D&A costs of heavy water and uranium are significantly different.

SE costs are used in economic evaluations while D&A costs are used for accounting practices and for estimating rate impacts.

This differentiation was made in presentations to the Ontario Nuclear Cost Inquiry and accepted by them.

Present Values

Different demand and supply options will have different electricity reduction or production patterns and service lives. Because of this, each option and each demand/supply plan will have its own schedule of expenditures. One may be expensive to build but cheap to run compared to another which costs less to install but has high annual operating costs. It is therefore necessary to have an evaluation technique that allows comparison of options with different expenditure patterns.

The standard way to compare different patterns of expenditures is the present value technique otherwise known as the discounted cash flow technique. The accumulated present value of a project is a single cost that captures the full life cycle cost of that project. Tomorrow's cash expenditure is less valuable than today's, not only because of inflation, but also because cash today can be invested to earn a return for future uses. The expenditures in future years are discounted to a common year using a discount factor derived from Ontario Hydro's corporate financial discount rate. In this report the common year for present values is 1989.

$$\text{Present Value} = \frac{\text{Expenditure}}{\text{Discount factor}}$$

The cumulative present value is the sum of the individual present values.

The Discount Factor

The discount factor is given by the formula

$$D = (1 + i)\ t$$

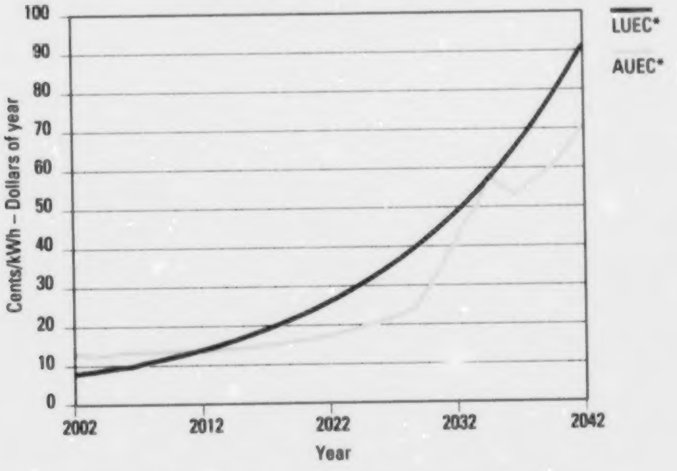
Figure 6–7 **Ontario Hydro Corporate Financial Discount Rate (CFDR) Computation**

Example only

- Debt capital share = 83%
- Debt capital rate = 10%
- Other capital* share = 17%
- Equity rate = 13.4 %
- CFDR = 0.83 x 0.1 + 0.17 x 0.134 = 10.52%
- CFDR is rounded to 10.5%
- CPI for the year = 5%
- Real CFDR = 10.5 - 5.0 = 5.5%

*Other capital includes reserves for debt retirement and rate stabilization.

Figure 6–8 **Levilized Unit Energy Cost of a Nuclear Station in Escalated Dollars**



*Direct and allocated costs for existing site

where i is the discount rate and t the number of years.

The discount rate represents a weighted average of the cost of debt and other capital (reserves for debt retirement and rate stabilization). The interest rate (cost of debt) used in determining the discount rate is the forecast average cost of Hydro debt. The cost of other capital is estimated to be higher than the cost of debt capital. Figure 6–7 shows an example of how Hydro's corporate financial discount rate is calculated.

The discount rate varies depending on whether one is working in escalated or real dollars. When working in escalated dollars the discount rate is projected to be, for the period 1989–2014, in the range of 10.25% to 11.75%. The 'real terms' discount rate is in the range 4.5 to 5.75%.

The evaluations of the individual options were developed in early 1989. Since then there have been some changes including a charge by the government of 0.5% for the provincial guarantee of Hydro's debt. Sensitivity analysis shows that the effect of these changes on the choice of options and plans is very small.

The present value technique allows comparison of two options that do the same job but have expenditure patterns that are different over their lives. The option with the lowest accumulated present value cost will result in lowest costs to customers over the long term.

Levelization – Options

Comparison of options of different sizes is facilitated by using the unit cost of producing electricity. However size is not the only thing that is different between options. Costs, such as the AUEC shown in Figure 6–4, vary from year to year. Options also have different lives.

Levelization allows comparison of options despite these differences.

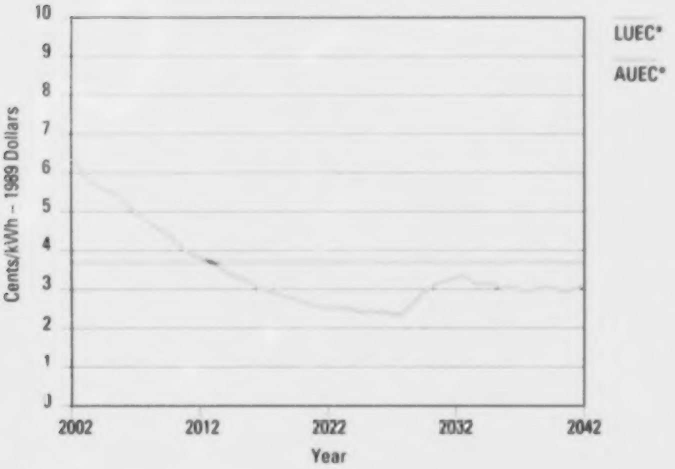
The simplest way of levelizing is to take the average, but this ignores the time value of money, explained in the previous section. Ontario Hydro levelizes its costs by an annuity method. This involves allocating costs in equal annual real installments over the operating life of the option in such a way as to give the same cumulative present value as the original expenditures. This allows a meaningful average to be obtained. It allows comparison of options with different patterns of expenditures and different service lives.

The levelized unit energy cost (LUEC) is a single number expressed in cents per kWh. It is indicative of an option's long term costs. The LUEC can be expressed both on a Direct & Allocated (D&A) basis and on a System Expansion (SE) basis. LUECs of different options are comparable providing those options are used for the same role in the system. Figures 6–8 and 6–9 show the levelized unit energy cost of a nuclear station together with the previously shown AUEC.

The LUEC (D&A) and AUEC (D&A) represent the same costs over the lifetimes of the options. AUECs can be seen to start higher but end lower than LUECs. The constant dollar LUEC is the one number that characterizes the options lifecycle cost.

The LUEC (SE) of a future option in 1989 dollars is an appropriate indication of the long term electricity production cost of that option. It provides a simple comparison of supply options for planning purposes. The LUECs quoted in this report are generally on an SE basis.

Figure 6–9 **Levilized Unit Energy Cost of a Nuclear Station in 1989 Dollars**



*Direct and allocated costs for existing site

With regard to LUECs the Ontario Nuclear Cost Inquiry (ONCI) found:

"The levelized unit energy cost (LUEC) methodology provides an appropriate means of reducing the total lifetime costs of a nuclear generating station to a single value for use in making comparisons with other options."

"The Hydro methodology is consistent with methodologies used by the United States Department of Energy (DOE), the Electric Power Research Institute (EPRI), Electricite de France (EDF), the International Union of Producers and Distributors of Electrical Energy (UNIPEDE), The Organization for Economic Cooperation and Development (OECD), and the International Atomic Energy Agency (IAEA). Thus, the method is internationally recognized and used."

Allocation of Costs to a Plan Study Period

Economic analysis of demand/supply plans is concerned with cost evaluation, not just over a study period, but over the long term. However, the practicalities of analysis make it necessary to compare the performance of the plans over a specified period of time. This plan spans 25 years, 1990–2014. This planning period is shorter than the life of some options.

Some plans will introduce options that have useful lives of 40 years or longer. Hydraulic generating stations, for instance, may have useful production lives of 90 years or more. While the benefits of this type of option begin during the planning period, they continue well beyond the 25 year planning horizon. On the other hand, because most of the station's cost occurs during construction, most of the life cycle costs occur during the first

3 to 4 years of its life cycle and that is within the 25 year study period. It would be inconsistent to look at all the costs and only part of the benefits.

This inconsistency can be solved by using levelization to allocate the costs to each year of the option's life. For a nuclear station this is illustrated in Figure 6–10. The real levelized cost of the Capital and OM&A cost of a nuclear unit expressed in constant 1989 dollars is about $200 million per year. This includes the costs of retubing and post operation costs. If a nuclear unit becomes fully operational by the end of 2002, then it contributes 12 years of operation during the study period (2003–2014 inclusive). The capital and OM&A costs allocated to the study period are 12 annual payments of $200 million. These include an appropriate proportion of the costs in years beyond the study period. By present valuing the allocated costs of all options in a plan, one integrated demand/supply plan can be compared with another of a different composition.

Long Term Costs

For each alternative plan, the costs are allocated to the 25 year planning period, present valued and compared. In some instances, this method does not bring out the cost implications of decisions in the plan which extend long after the end of the planning period. Decisions which have small benefits within the planning period may have large benefits beyond the planning period.

For example, consider a choice between a 40-year lifetime base load nuclear station which has a 25% lower levelized unit energy cost than the same sized 40-year coal-fueled station. Let us assume one plan specifies a coal fueled station and an alternative plan specifies a nuclear station to meet the base load requirement starting in 2010. The case with nuclear station will show up as having lower costs in the 25 year planning period. However, only a small part, approximately 25%, of the benefit will show up in the comparison of the plans which end at 2014.

This report makes plan comparisons for the 25 year plan period. In addition, the cost implications beyond the end of the period are also made using two methods.

One method used is to extend the plan cost comparisons by ten, twenty and thirty years to show the longer term implications.

The plan cost estimates are extended into the future by estimating the differences in the plans in the last year within the planning period and assuming that these differences continue unchanged beyond the planning period. The implication of this assumption is that plan differences in 2014 extend beyond 2014 without being reduced or increased by subsequent planning decisions.

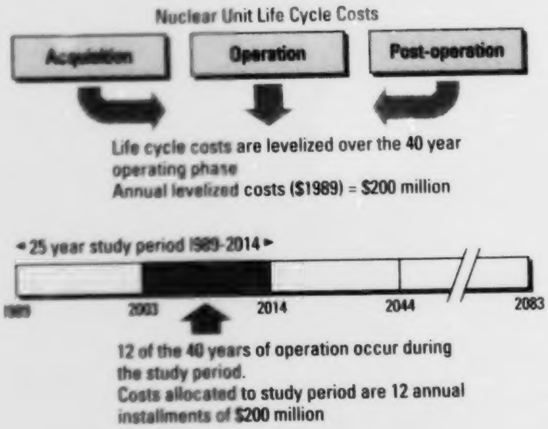
The second method used is to compare the lifetime costs of option choices based on their levelized unit energy costs.

To continue with the above example, using the LUEC method, and an 80% ACF, the lifetime present value cost saving of a 4 X 881 MW Candu station over an equivalent conventional steam cycle US coal-fueled station is 0.8 cents per kWh, or $3.6 billion present valued to the in-service year 2010. This saving is $1.25 billion if present valued to 1989, of which only $313 million is allocated to the planning period.

Uncertainty – Expected Costs

It is also necessary for cost evaluations to recognize and deal with the uncertainties that are inherent in the future. Uncertainty intro-

Figure 6–10 **Allocation of Levelized Costs to the Study Period**


Nuclear Unit Life Cycle Costs
Acquisition
Operation
Post-operation
Life cycle costs are levelized over the 40 year operating phase
Annual levelized costs ($1989) = $200 million
◄ 25 year study period 1989-2014 ►
1989
2003
2014
2044
2083
12 of the 40 years of operation occur during the study period.
Costs allocated to study period are 12 annual installments of $200 million

duces financial risks into the planning process. Minimizing risks generally results in an increase in costs, and minimizing costs often increases risks. One of the tools used by decision makers to balance risks with costs is the "expected cost" concept. The goal is to minimize the long term costs of decisions, recognizing uncertainties in the way the future may unfold.

In mathematical terms, the expected cost of a plan is the sum of all outcomes of the cost of a plan multiplied by the probability of the outcome.

Expected Cost =
 Cost(outcome 1) x Probability (outcome 1)
+ Cost(outcome 2) x Probability (outcome 2)
+ ...
+ Cost(outcome n) x Probability (outcome n)

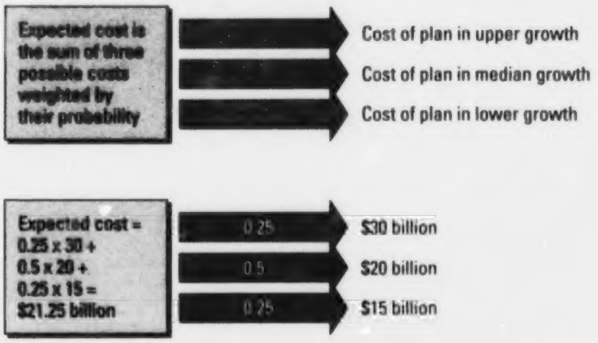
Let us consider an example, as shown in Figure 6–10. For the upper forecast the plan costs \$30 billion, for the median forecast the plan costs \$20 billion, and for the lower forecast it costs \$15 billion. Let us further assume that the probability of the upper, median and lower forecasts are 25%, 50%, and 25% respectively. The computation of the expected cost is \$21.25 billion as illustrated in Figure 6–11.

The method is extended to account for uncertainties in fuel costs, construction costs and interest rates. The expected costs of plans have been determined and are shown in Chapter 15.

Social and Environmental Costs and Benefits

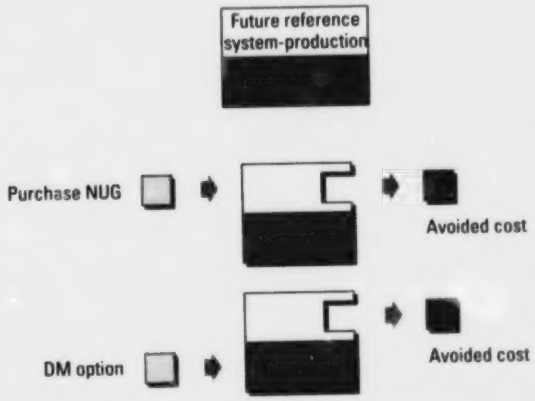
Costs are incurred by Hydro to mitigate social and environmental impacts associated with the supply and delivery of power. There are other social and environmental costs and benefits for the community, which are not

Figure 6–11 **Expected Cost Concept for Evaluating Demand/Supply Plans**


Expected cost is the sum of three possible costs weighted by their probability
Cost of plan in upper growth
Cost of plan in median growth
Cost of plan in lower growth
Expected cost = 0.25 x 30 + 0.5 x 20 + 0.25 x 15 = \$21.25 billion
0.25
\$30 billion
0.5
\$20 billion
0.25
\$15 billion

The Lambton station near Sarnia. Demand management will help minimize the use of coal.

Figure 6–12 **Avoided Cost Determination**



reflected in costs incurred directly by Hydro. These external costs and benefits are discussed below. Even when a monetary impact can be estimated, there is an issue as to whether, and how, these cost effects should be included in comparisons of options and in the estimation of avoided costs.

The analysis conducted in the development of the Demand/Supply Plans includes those costs which are borne directly by Hydro. It is these costs which can properly be included in Hydro's rates. Costs and benefits for the Ontario community, beyond these direct costs, are not factored into the cost comparisons.

Ontario Hydro adopts measures necessary to meet all environmental regulations that affect the design, construction and operation of its facilities. As a part of good engineering practice, and to show a leadership role, Ontario Hydro also adopts many other measures to reduce environmental impact. The costs of all these measures are included in capital and operating costs as appropriate, and are passed on to customers through rates. Hydro also makes payments to communities to mitigate the social impact of Hydro's construction activities.

Social and Environmental Costs Incurred Directly by Hydro

The costs Hydro incurs to mitigate social and environmental effects amount to many hundreds of millions of dollars per year. Some of these costs are dictated by regulation, for example, acid gas emission regulations. Hydro has just committed the construction of flue gas desulphurization equipment for two 500 MW units at Lambton at a cost of $450 million. Other costs are for steps which go beyond regulatory requirements. For example,

- Hydro has been buying low sulphur coal at an annual extra cost of $100 million.
- Nuclear stations include systems that reduce the radioactivity emission to a small percentage of the regulated limits.

In addition, Hydro makes payments to municipalities to mitigate the social impact of Hydro's activities in areas where Hydro has major projects. These payments are negotiated with the affected community during the site selection and project approval process. For the Bruce Nuclear Power Development the impact payments to Bruce Township have amounted to $1.2 million from 1981 to present, and about $1.2 million annually to nine area municipalities. This is in addition to normal grants in lieu of taxes. Hydro also makes payments to the general reserve fund of other levels of governments as required, for example, water rentals for hydraulic energy and debt guarantee charges to the Province. These payments are included in the general revenues of the Province, and help support government programs.

Expenses are also incurred to mitigate the effects of transmission and distribution facilities. Special transmission towers are used to run high voltage lines through built up communities. Hand-cutting and other higher cost methods of vegetation control are being substituted for herbicides on rights-of-way.

These examples are only some of the costs of reducing and mitigating social and environmental impacts. Although not easily segregated, many other costs of this type have become part of the normal good engineering and business practice that is followed in the design, construction, operation and decommissioning of Hydro's system. All of these costs are appropriate business costs and are included in the cost estimates of Hydro's options, Hydro's rates for selling electricity and Hydro's avoided costs.

Social and Environmental Costs and Benefits External to Hydro

Apart from the costs incurred by Hydro, there are still social and environmental effects which result from Hydro's activities. These effects can be negative and thereby imply a cost. Examples might include acid gas emissions within the regulations, flooding of land for hydraulic stations, and small increases in water temperatures around nuclear and fossil fueled stations. However, the effects can also be positive; for example, the control of rivers to permit navigation and prevent flooding, the creation of parks, and increased economic activity and employment. There is some question as to whether these costs and benefits should be included in cost evaluations. Even if desirable, these costs and benefits are difficult to estimate in monetary terms given the diffuse nature of the impacts and the wide variety of effects.

Some impacts can be treated in cost evaluation as either internal or external costs. For example, the effect of acid gas emissions due to increased coal burning can be accounted for:

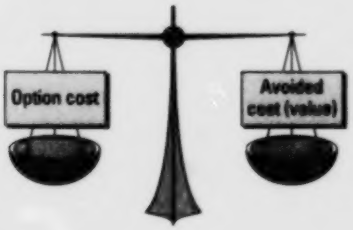
- as an external cost by assuming that acid gas emissions increase with a resulting cost to society; or,
- as an internal cost by assuming that acid gas emissions are held level by taking additional control measures – with a resulting cost to Hydro.

For avoided cost calculations, Hydro adopts the second approach and internalizes the costs of mitigating acid gas emissions.

Social and Environmental Costs Applied to Exports

Under the National Energy Board regulations, Hydro is required to show that the price at which electricity is exported recovers all the costs in Canada including any identifiable social and environmental costs. These costs specifically address the impacts of emissions including impacts on human health, building materials, and terrestrial ecosystems. At present the estimated social and evnironmental costs are 0.04 cents/kWh. This estimate was reviewed by the National Energy Board in 1981 at their last hearing on Hydro's licence to export to the U.S. The estimate will be revised for the application for renewal of Hydro's licence in 1991. This cost is added to the price of Hydro's exports and the resulting revenue benefits Ontario customers through lower electricity rates.

Figure 6–13 **Cost and Value of Options**



Social and Environmental Costs Application to Avoided Costs

The avoided costs that Hydro uses include the social and environmental costs incurred by Hydro but do not include social and environmental costs and benefits external to Hydro. This reflects normal business practise. In Hydro's judgement, including additional costs and benefits on an equitable basis would be impracticable. For example, the social and environmental costs and benefits of NUG options and such options as the purchase from other utilities will be very dependent upon the technology employed and the sites involved. Accordingly, it would be extremely difficult to estimate the differences in such costs and benefits between Ontario Hydro projects and other projects.

Social and Environmental Costs in this Report

The way in which social and environmental costs, benefits, and other effects are reflected in this report include the following:

- the costs of ensuring high standards of environmental performance are included for all new options. These costs and environmental effects are discussed in Chapter 14 for major supply options;
- avoided cost calculations include social and environmental costs incurred by Hydro, including the cost of ensuring no increase in acid gas emissions resulting from incremental coal use;
- the chapters relating to demand management, NUGs and hydraulic generation include con-

sideration of social and environmental effects;

- effects of the major supply plans are discussed qualitatively in Chapter 15;
- social effects of the plans include the effects on acid gas emissions, carbon dioxide, solid waste, radioactivity, and are discussed in Chapter 15.
- environmental effects of the plans include the effects on acid gas emissions, carbon dioxide, solid waste, radioactivity, and are discussed in Chapter 15.

Further discussion of social and environmental costs, benefits and effects is included in the environmental analysis document.

AVOIDED COSTS

Concept and Application

In Chapter 5, the discussion focused on Ontario's need to develop additional demand and supply options. In the remainder of this chapter, the discussion turns to a costing method that allows Ontario Hydro to integrate demand management and non-utility generation opportunities with the utility's future supply plans.

A primary objective of Ontario Hydro's integrated planning process is the maintenance of Ontario's electricity supply and price advantages for the future benefit of all customers. Many factors will help determine Hydro's success in doing so, but chief among them will be its success in developing the full economic potential of all available options: demand management, non-utility generation, and new supply.

The primary method used by Hydro to establish the economic value of demand management and non-utility generation is the avoided cost concept. By calculating Ontario Hydro's avoided costs, the costs and benefits of various demand management and non-utility generation projects can be compared with alternative supply options.

Avoided cost is defined as the supply costs which are avoided when any demand or supply option is substituted for an equivalent part of a demand/supply plan.

To determine the avoided costs of an option it is necessary to have a reference system that would be developed in the absence of the option in question.

The reference system is divided into two sections, production and utilization in the same way as was discussed in the section on Total Customer Cost. When a NUG option is added to the production system, it adds to the capacity and energy capability of the future reference system.

To meet the same load some parts of the reference system will now no longer be necessary and can be avoided. The avoided cost of the option is the cumulative present value of the costs of the parts of the reference system that are avoided.

In a similar way, when a demand management option is added to the utilization system, it reduces the demand on the production system and some of the production system costs can be avoided.

Ontario Hydro calculates avoided costs as accurately as possible because estimates above or below the utility's true avoided costs would result in adverse impacts on customers.

By over-estimating its avoided costs, Hydro would raise the price of electricity for provincial consumers by encouraging the development of options that are more expensive than major supply options.

By under-estimating its avoided costs, the full economic potential of these options would remain unrealized because Hydro would not be able to encourage or capture all of the available economic opportunities. In this instance, Hydro could find itself making a larger commitment to new supply options than was actually required or necessary.

In addition to helping Hydro estimate the potential and value for non-utility generation and demand management, avoided cost calculations are used by Hydro to evaluate a number of internal design and operating decisions including for example screening its hydraulic potential.

Establishing Avoided Costs

Avoided costs can be established by making a number of interactive or repetitive calculations. An estimate of avoided costs is made based on previous planning experience and current estimates of economic supply options – and then used to determine the potential for demand management and non-utility generation. Once these estimates have been made, decisions can be made on the amount of new supply options to include in future development plans.

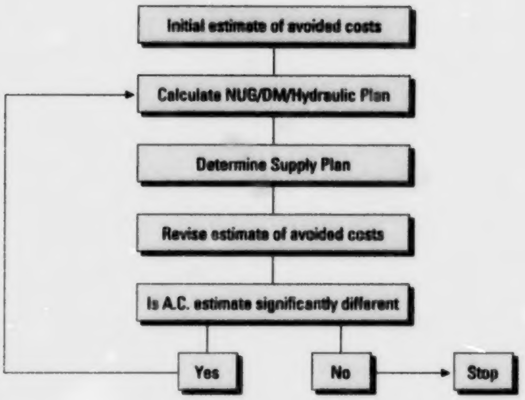
Once a supply plan has been identified, a new avoided cost estimate can be determined based on that plan. This estimate is then compared with the original estimate. If the new estimate is significantly higher than the original estimate, the amount of non-utility generation and demand management in the plan is increased. If the estimates are lower, the reverse holds true.

The calculations are repeated until a convergence occurs. This generally takes place within a few iterations.

Determining Avoided Cost Values for Demand Management and NUGs

In calculating the avoided cost value of demand management and non-utility generation,

Figure 6–13 **Establishing Avoided Costs**


Initial estimate of avoided costs
Calculate NUG/DM/Hydraulic Plan
Determine Supply Plan
Revise estimate of avoided costs
Is A.C. estimate significantly different
Yes
No
Stop

Hydro considers how each project will affect the operation of the province's power system. The avoided costs of options vary with the timing of delivery, dispatchability,† reliability, life and location. This section will address these issues.

Timing and Dispatchability

Ontario Hydro's avoided costs vary with the timing of the delivery. Avoided costs for an option that is capable of delivering power during peak demand periods will be higher than one that is only capable of delivering power at low demand periods, as it saves higher priced fuels and the construction of additional generation and transmission facilities.

This value of the timing of energy production is also the reason for the value of dispatchability. To maintain system reliability, Hydro must exactly match the amount of generation producing power with customers' electricity requirements as it varies minute by minute, day in and day out throughout the year. Dispatchability is the ability of the Ontario Hydro control centre to control the time at which an option produces power. For instance, for a NUG which can only operate at low annual capacity factor (ACF), say 10%, but can produce its energy at times requested by Hydro's system control centre for the hours when Hydro most needs the capacity, the unit energy avoided cost is likely 2 to 3 times higher than that for a similar NUG whose energy production is purely dictated by the NUGs own concerns. Avoided costs will vary with the dispatchability of non-utility generation because dispatchability permits Hydro to plan and operate its system better.

The pattern of production from a hydraulic plant affects its value and is a function of the site characteristics and the design of the facility. The value of hydraulic projects increases when water storage is possible, because this provides controllable peaking capability. The larger and more flexible this storage capability is, the more valuable it is. In effect, it is more dispatchable. These factors must be taken into account in evaluating the avoided cost of proposed hydraulic plant whether developed by Hydro or a NUG.

Reliability

Different NUGs and demand management programs will also have different degrees of reliability. A demand management program or NUG that has a high probability of being available at times of capacity shortage has a higher value than those that are less dependable. This is because Hydro's supply capability can be reduced more for dependable programs than less dependable ones. For example, a NUG would have a lower avoided cost if it had a lower probability of being available because of equipment breakdowns.

Life

Another factor which affects an option's avoided cost is the life of the project. The longer the life of an option, the more energy it produces and its avoided cost in cumulative present value terms is higher.

Location

The location of a non-utility or hydraulic generation project will also affect its avoided cost. If a NUG is located in a region of the province that does not have adequate generation to meet demand, the project will enable Hydro to reduce the cost of transmitting power into that region. The avoided cost for this project will therefore be higher than a project located in an area with adequate generation.

Figure 6-14 Examples of Avoided Costs
1989 dollars

	$/kW	cents/kWh
Non-Utility Generator (1994–2014)		
80% ACF	2920 (2720)*	3.4(3.2)
40% ACF	1980 (1360)	4.6(3.2)
10% ACF	1080 (340)	10.0(3.2)
Hydraulic		
Niagara River development	2830	5.3
Demand Management		
(Thermal Envelope Upgrade, 2000-2040)	2380	6.9

** Numbers in brackets assume non-dispatchability*

Note cents/kWh and $/kW are alternative ways of presenting the costs they are not additive

For demand management options, savings to the transmission and the distribution systems may be possible as a result of efficiency improvements. While individual electrical efficiency improvements may or may not affect the cost of local distribution. The net effect on average for a program that is implemented across the province will likely be a reduction in distribution and transmission costs. A credit is therefore applied based on the average effect.

Current Estimates of Avoided Cost

Avoided costs, as described in the previous section, are very option-dependent. This section looks at specific examples. The determination of these costs is described in Chapter 16.

Figure 6–14 shows the calculated expected avoided costs for five examples based on the proposed plan: three non-utility generators; a hydraulic scheme; and a demand management option. The values are presented in two ways: cumulative present value dollars per kilowatt, and cents per kilowatt-hour produced or saved. The values are presented in constant 1989 dollars. These are alternative ways of presenting the costs, they are not additive.

The three non-utility generators are assumed to be dispatchable and connected to the bulk transmission system, and to operate from 1994 to 2014, at 80% , 40% & 10% ACF respectively. They are 90% reliable. It can be seen that the high ACF avoided cost (3.4 cents/kWh) is comparable to the LUEC for nuclear shown in Figure 6–14. This comparison is valid as nuclear is operating at the same capacity factor in the same base load role. It can also be noted that while the unit energy price increases for low capacity factor operation, the value measured in dollars per kilowatt installed, decreases. This reflects the fact that while the energy produced may be more valuable, there is less of it. Also shown in parenthesis are the values assuming the projects are not dispatchable. It can be seen that the avoided cost is less than if the energy had been dispatchable.

The hydraulic example is the Niagara river development. It has a life of 90 years and a net capacity of 550 MW. It has limited storage and is dispatchable on a daily basis. The cost-value comparison of this and other hydraulic projects is shown in Chapter 12.

The demand management option is a thermal envelope upgrade to be done in 2000 and good for 40 years. It saves 3.52 kW of customer load on the coldest winter day and 11,150 kWh of load per year. The avoided cost includes transmission and distribution credit. The avoided cost also includes credit for the energy being saved in the winter because the insulation produces most savings in the heating season.

It will be seen that the values range from 3.2 to 10.0 cents/kWh or $340 to $2920/kW, depending chiefly on capacity factor, life, and dispatchability.

Summary

The costing concepts described in this chapter has been applied consistently to evaluate options and plans in many chapters of this report.

The avoided costs described at the end of this chapter are based on analysis of the proposed plan using the present value, levelization, allocation, and system expansion concepts described earlier in this chapter. Avoided costs are used to establish the contribution of demand management (Chapter 7), NUGs (Chapter 8) and hydraulic (Chapter 12).

Chapter 15 includes an economic cost analysis of the planning cases on an economic basis as well as a financial analysis on a direct and allocated basis. ■

7. THE DEMAND MANAGEMENT PLAN

Demand management consists of measures taken by Ontario Hydro and municipal utilities to influence the amount and timing of customer electricity demand. Some demand management programs have been around for many years.

These include interruptible rates for customers (primarily industrial) willing to reduce load in the event of system shortages, as well as information programs to encourage more efficient energy use. Other programs are new – for example, an incentive program for high efficiency commercial lighting designed to reduce demand, and time-of-use rates designed to shift electricity use to off-peak periods.

This Chapter describes Hydro's demand management activities from three perspectives:

- Concepts – understanding how demand management works;
- Opportunities – the potential of demand management in Ontario;
- Plan – programs and expected results.

Hydro's Demand Management Plan emphasizes three main areas: load reduction, load shifting, and peak clipping. The expected results of Hydro's Demand Management Plan compare favourably with the experience and targets of other North American utilities active in this area.

Hydro's Commitment to Demand Management

Economic demand management is given top priority in the Demand/Supply Planning Strategy and is an integral part of the Demand/Supply Plan to meet future customer needs. Hydro is committed to aggressively pursue opportunities to reduce or shift demand that is in the customers' interest and will keep Total Customer Costs low, using techniques that generate customer support. Through reducing growth in demand, Hydro will be able to reduce the requirement to build new supply facilities, reduce the consumption of coal, oil and gas, and reduce the environmental effects of electricity supply.

The Energy Management Branch was established to focus efforts on the development and delivery of demand management programs. An ambitious demand management plan has been formulated and some programs are already under way. This plan will evolve as customers' needs change and as Hydro and customers gain experience with programs. Hydro's goal is to achieve the maximum attainable load growth reduction from economic demand management.

Hydro plans to spend about 1 billion dollars on demand management programs by 1994 and projects that three billion will be spent to the year 2000. These expenditures are expected to result in a cost effective demand reductions of 3,000 MW and 10 TWh in the year 2000. This plan projects cost effective demand management reductions of over 4800 MW and 17 TWh in 2014. In keeping with the goal to achieve the maximum attainable load growth reduction, the planned reductions to 2014 do not represent a ceiling.

Ontario Hydro will not be able to deliver its demand management targets on its own. It will require the substantial support of the Ministry of Energy, electrical contractors, manufacturers, distributors, builders, etc. The most critical requirement is for the support and commitment of its partners in the distribution of electricity in Ontario – the municipal electrical utilities and the association that represents them, the Municipal Electrical Association (MEA). Since the municipal utilities deliver electricity to over 75% of the end use electricity customers, their support is essential. The MEA and individual utilities have given a strong endorsement to demand side management and their continuing support is a fundamental premise upon which those plans are based. There will need to be continuing involvement and participation with the municipal utilities and the MEA throughout the planning period if the demand management targets are to be achieved.

Types of Demand Management

It is common in North America to classify utility efforts to influence electrical demand in five categories:

- Load Reduction
- Load Shifting
- Peak Clipping
- Valley Filling
- Load Building

Ontario Hydro's demand management programs are designed to maximize customer satisfaction through using electricity more efficiently. Programs that reduce customers' energy bills, improve comfort or productivity, or have environmental benefits for the customer, can, in some cases, build load. Hydro has no programs whose objective is to build load.

An ambitious demand managment plan has been formulated and some programs are already underway. This plan will evolve as customers' needs change and as Hydro and customers gain experience with programs. Hydro's goal is to achieve the maximum attainable load growth reduction from economic demand management.

- Load Reduction is achieved primarily through improvements in the efficiency of electricity use. These measures reduce the amount of electricity required to satisfy a customer's need, for example, the substitution of high efficiency lamps for lower efficiency lamps.
- Load Shifting reduces system peak demand by shifting some electricity demand from high-use to low-use periods. This can be achieved through direct control of customer loads and indirectly by special rate and financial incentives to reduce use of electricity during peak hours. Although load shifting reduces the need for peaking capacity, it does not normally reduce the overall consumption of electrical energy. An example of load shifting through direct control is the use of large capacity water heaters controlled by the utility to consume electricity at off-peak times only.
- Peak Clipping can also be achieved in a number of ways. One of the most important of these is Capacity Interruptible Load contracts with customers who, in return for reduced rates, agree to curtail their consumption of electricity upon request to help the utility deal with periods when system demand is about to exceed the utility's ability to supply.
- Valley Filling seeks to encourage the growth of customer loads during the off-peak hours ("valleys"). This levels the demand on the supply system and increases the efficiency of utility investment in generation and delivery facilities.
- Load Building seeks to encourage consumption of electricity during both peak and off-peak hours. For example, load building programs can use special rates to attract new industry or to encourage existing customers to switch from other fuels to electricity.

The various effects on daily load shape are illustrated in Figure 7–1

While Ontario Hydro's Demand Management Plan has no load building objectives,

[illegible]	[illegible]
Load Reduction	Electrical Efficiency Improvements
Load Shifting	Time-Of-Use Rates, Thermal Cool Storage and Direct Control
Peak Clipping	Capacity Interruptible Load
Valley Filling	None
Load Building	None

Hydro's Research Division provides advice to customers about efficient electric technologies. This service may result in some load building. These activities support the objective of helping electricity customers increase their energy efficiency, productivity, and competitiveness.

Because of the central role of electrical efficiency improvements in the Demand Management Plan, the remainder of this section is devoted to a description of the concepts underlying this aspect of demand management. Many of the program ideas developed in this area are also useful in understanding other areas of demand management.

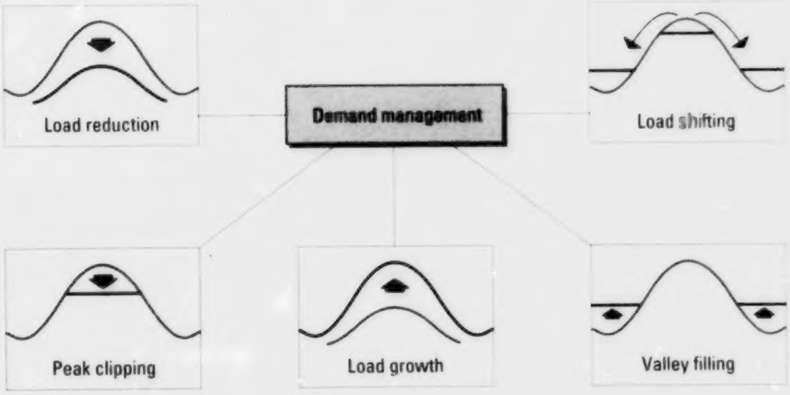
An Overview of Electrical Efficiency Improvements

The single most important way to reduce electricity demand is to improve the efficiency of electricity use. The basic aim of Hydro's electrical efficiency improvement programs is to satisfy customers' needs for electric services such as lighting and space heating – while using less electricity.

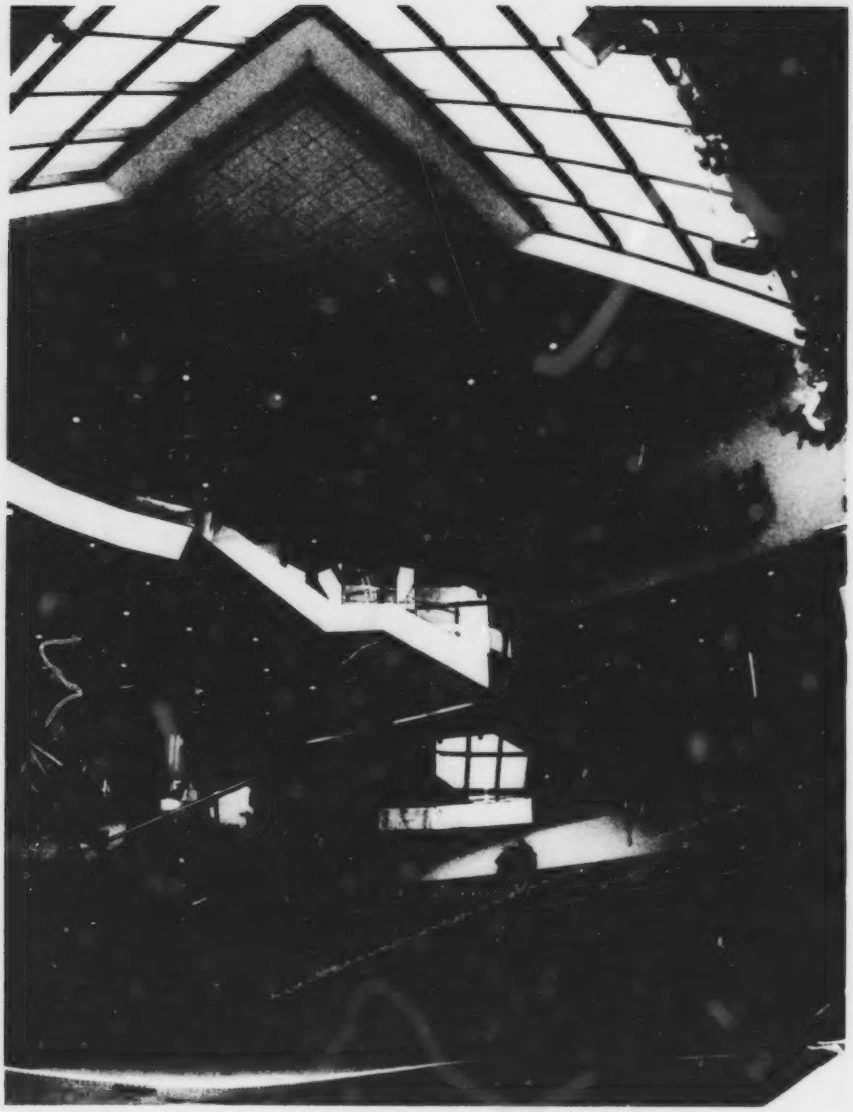
Such reductions can be achieved in two different ways. One involves encouraging customers to choose equipment that operates at higher than normal efficiency – in other words, that uses less electricity to do the same job. Improving electricity use through the introduction of efficient equipment technologies leads to more stable and predictable energy savings.

The other way to promote efficiency is to advise them on how to make more efficient

Figure 7–1 **Effects of Demand Management**



This plan projects cost effective demand management reductions of over 4,800 MW and 17 TWh in 2014.



Energy-efficient lights will give customers quality lighting from fewer kilowatts.

use of their electrical equipment. This approach focuses on people's behaviour. Both of these approaches are important and complementary.

Customers can reduce waste by turning off lights when they are not needed. But, even when customers are convinced of the benefits, changes to entrenched habits are sometimes difficult to sustain. This is why utility information programs will continue to play an important role in reinforcing the importance of energy efficiency.

A more dependable way for customers to reduce lighting costs is to install high-efficiency fixtures which provide the same amount of light using less electricity. While more efficient equipment virtually guarantees lower electricity bills, it does carry other costs – notably the higher capital costs often associated with more efficient equipment.

Thus, Hydro's programs for efficiency improvements contain a blend of advice on more efficient use of equipment and encouragement to select more efficient equipment. They also include financial incentives where necessary to help offset customers' incremental capital costs – shortening payback periods for customers who adopt more efficient equipment. Financial incentives may include reduced rates, grants, loans, or rebates.

Energy efficiency programs have to appeal to customer values and interest. Saving money is a major incentive for electricity customers to participate in energy efficiency programs. But people may also wish to adopt energy-efficient electrical equipment for reasons other than cost, such as conserving resources or protecting the environment.

A Progress Report on Efficiency Improvements – Three Examples

Commercial Sector – Lighting accounts for about 40% of electricity use in the commercial sector. Much of this lighting is inefficient compared to the best available lighting products and design practices.

Hydro has designed an incentive program for lighting based on considerable research and consultation with lighting suppliers, utilities and customers. To ensure customer service standards are met lighting design must meet guidelines set by the Illuminating Engineering Society.

Promotional materials reflect targeted appeals to different segments of the commercial sector with divergent needs and expectations. For example, lighting program design has to recognize that efficient metal halide lamps do not have equal value in office and retail applications. While these lamps can effectively light a broader area than fluorescent lamps, replacement is not as convenient – a crucial consideration in a retail environment but not as important in offices.

Industrial Sector – In 1989 Ontario Hydro launched a province-wide program to promote the use of high efficiency motors. This program is designed to reduce the growth in demand by 400 MW by the year 2009 by making these motors the standard in Ontario within the next ten years. Today, they account for less than 3% of annual motor sales. The development of this program illustrates how the effectiveness of a program may depend on careful research.

Several years ago Hydro's market research established that high efficiency motors had captured a ver[illegible]ll share of the motor market, even though the potential payback to customers in electricity savings would offset the higher cost of these motors. An economic analysis showed that the value of high efficiency motors to the Hydro system is in the range of $40 to $50 per horsepower. Since motors account for 75% of industrial electricity consumption and high efficiency motors are between three to eight percent more efficient than today's standard models, Hydro decided to commit considerable resources to promoting much greater use of high efficiency motors in Ontario.

A test program was run using financial incentives to shorten payback periods for customers. But despite extensive research and careful consultation with customers, the program was not attracting wide interest.

Further studies showed that most wholesalers were not able to obtain high efficiency motors. Rather than lose sales, many suppliers offered deals on standard motors that were as attractive as Hydro's incentives for high efficiency motors.

The high efficiency motor program has been designed to take these research findings into account. The program features include:

- rebates to customers which reduce customer payback periods to less than two years;
- incentives to distributors which offset the cost of handling a broader range of products; and
- education programs and cooperative promotion efforts with manufacturers and distributors.

Residential Sector – One of Hydro's objectives in the residential sector is to promote awareness of, and interest in, demand management. One popular program designed to achieve this was a contest to find energy efficiency tips from customers.

When the program was announced, with prizes for the best entries, more than 10,000 responses were received. Award ceremonies were well publicized and attended.

The top suggestions were published in a booklet entitled "Tips – Energy Suggestions from the People of Ontario". Over 100,000 copies were distributed to people who called in to ask for the Tips booklet.

This awareness-raising program was followed by a province-wide promotion of efficiency-improving products in the fall of 1989 in cooperation with the Home Hardware retail chain. Coupons included in the special promotion gave residential customers discounts for the purchase of efficiency-improving products.

Winning over the Decision-maker

To be successful in their demand management programs, Hydro and the municipal utilities have to deal with three overlapping groups of people:

- people who pay electricity bills
- people who use electricity
- people who make electricity-related equipment decisions.

While it is obvious that customers have a built-in incentive to reduce their electricity bills, this is not necessarily true of other users, such as apartment dwellers who are not directly responsible for their electricity bills. Thus, programs to encourage more efficient use of electricity must be designed for both groups.

Because many people have little control over the type of electrical equipment they use, Hydro's efficiency improvement programs must also be aimed at the decision-makers who select the energy form and equipment to be used in factories, commercial buildings and housing developments. This group includes manufacturers, engineers, architects, builders, service trades and other individuals who may be neither the user nor the ones who pay the electricity bill for the equipment in question.

Decision-makers are often motivated to select equipment for convenience and short-term economies, rather than long-term savings. From a decision-maker's perspective, it may not be sensible to invest more capital up front for an efficient technology when the benefits are likely to be enjoyed at some point in the future by someone else.

It is Hydro's job to understand what measures are most appealing; to offer a broad menu of programs to choose from; and to develop innovative ways to motivate customers to act on economic efficiency improvement opportunities.

What About Incentives?

A demand management option is economic if the Total Customer Cost Test is satisfied. This evaluation is not affected by the level and nature of any incentive provided by Hydro.

However, when financial barriers are identified, Hydro estimates the level of incentives needed to overcome decision-makers' concerns about investment payback. The amount of the incentive cannot be greater than the avoided cost level and will generally be set to achieve significant penetration of the target market without attracting an undue number of free riders.[†]

The Cost Factor

Successful demand management often involves the use of financial incentives. Investing for future savings is not in itself so unusual. What is unusual is the idea that Hydro is prepared to pay customers to use less electricity.

When it does this, it incurs incentive costs and reduces sales volume. The result is that everyone is likely to pay slightly more per kilowatt hour, but participating customers will use fewer kilowatt hours and therefore their bills will be lower. Hydro is, therefore, offering a broad range of programs in order to ensure that the opportunity for participation is widespread.

In assessing demand management programs, Hydro applies a test called the Total Customer Cost Test. In this test, Hydro estimates the present value of:

- the incremental cost of more efficient equipment (e.g., the premium paid for high-efficiency lamps);
- program administration and delivery costs (the utility's cost in delivering the lighting program, including incentives where applicable); and
- changes in customers' operating costs (the customer's bill reduction as a result of lower consumption for lighting).

A program is economic if the sum of these customer and Hydro program costs is less than the corresponding present value of avoided supply costs - what it would have cost Hydro to supply the electricity not consumed because of the program in question.

The Time Factor

It takes time to build the basis for successful demand management programs:

- identifying combinations of market segments and technologies with economic potential for efficiency improvements;
- conducting the market research that will help in the design of effective programs;
- program testing and new product development;
- building credibility and relationships with decision-makers, customers and allies.

As indicated in Figure 7-2, Hydro has developed and is launching a broad portfolio of demand management programs across the residential, commercial, and industrial sectors.

Environmental Factors

Natural Environment

Generally, demand management options have favourable effects on the natural environment. Improvements in electrical efficiency can reduce the need for new generation, transmission and distribution facilities, and cut back Hydro's consumption of coal, oil and natural gas. Load shifting has similar benefits, allowing Hydro

Figure 7–2 **Increasing Customer Satisfaction Requires Strengthened Customer Service and Energy Management Requirements**

1983
1988
1992
1998
Regions, areas inspection and municipal utilities

Energy management	Phase I	Phase II	Phase III	Phase IV
Strategic direction	Development and introduction of energy management programs	Implementation of incentive driven energy management programs	Broad scale implementation of programs	Implementation level adjusted to market conditions
	• Strategy formulation • Pursue concept testing of efficiency & load shifting • Increased customer contact • Understanding customers better • Ally & channel development • Gaining municipal utility support • Encouraging electricity use where customers benefit • Promoting 'natural' conservation • Gradual resource increase	• Strategy refinement • TOU implemented • Incentive-backed efficiency initiatives implemented • Direct control load shifting implemented in early 1990s if TOU does not deliver required results • Major resource increase – a mega project committed and underway • A highly visible presence in the marketplace	• Strategy refinement • As in Phase II but all initiatives at full scale • Stability in resource level	• As in Phase III but level of effort will be adjusted to meet system and evolving customer needs

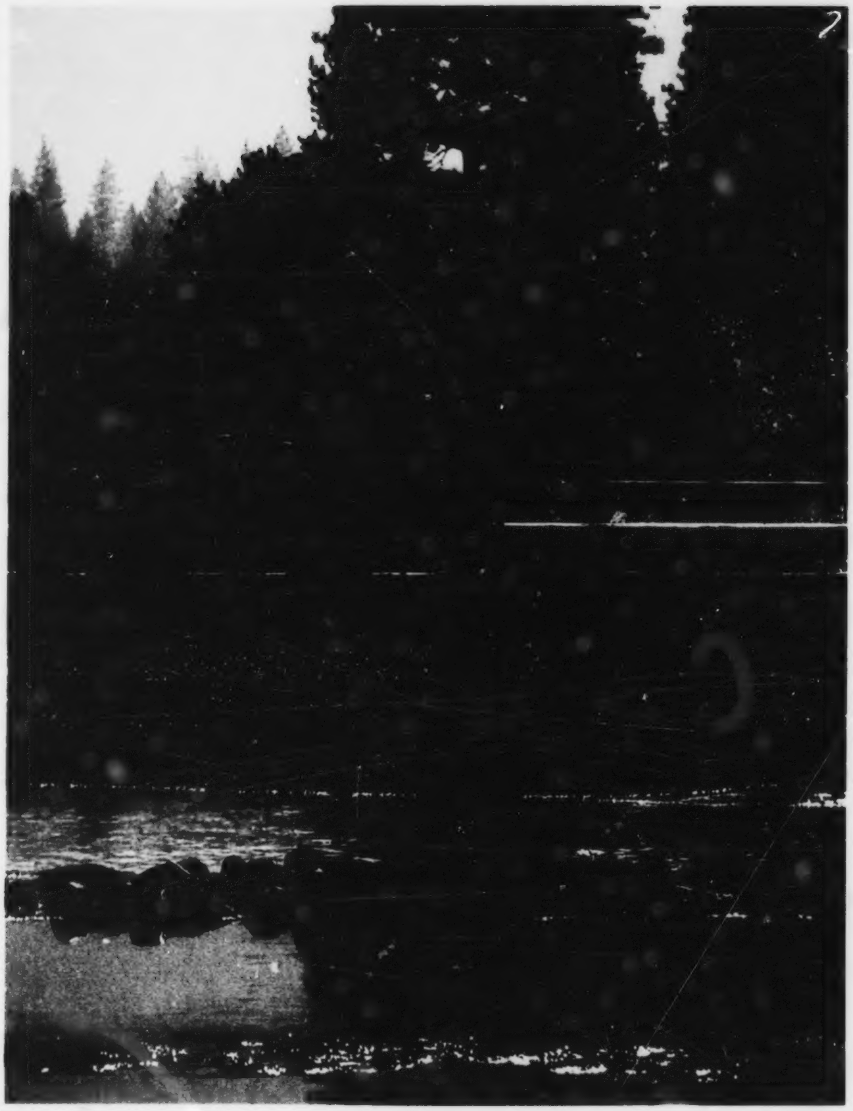
to substitute more economic generation facilities to meet shifted energy needs. To the extent that these benefits can be quantified, they are reflected in Hydro's avoided cost, crediting demand management initiatives with their environmental benefits.

Electrical efficiency improvement programs reduce energy and power consumption at all times. Accordingly, the environmental impact of all types of generation, e.g., hydro, fossil, and nuclear, are reduced.

A load shifting program does not reduce the amount of electrical energy consumed. The flattening of daily load shape tends to reduce the amount of peak and intermediate load and increase the base load. Since base load requirements are met with nuclear and base-load hydraulic generation, the amount of fossil generation required is reduced. The environmental issues associated with fossil and nuclear generation are discussed in Chapters 14 and 15.

The environmental characteristics of demand management options themselves have not been scrutinized as extensively as supply options. Some of the potential environmental effects relate to the manufacture of energy efficient equipment and to the disposal of inefficient equipment. Preliminary estimates of these effects, however, indicate that they are negligible when compared to the effects of producing the displaced electricity through conventional generation.

The potential environmental effects of demand management programs need further study. Some programs will require the management of environmentally sensitive materials. For example, a program to replace standard fluorescent ballasts requires the safe disposal of old PCB-contaminated ballasts; a program to encourage the use of high efficiency refrig-



Efficiency improvements reduce the need for new facilities, and help protect the environment.

erators may require the safe extraction of freon (CFCs) from old equipment; and, a program to encourage weatherization of homes would require air exchange equipment to reduce concentrations of air pollutants such as radon gas, formaldehyde, and carbon monoxide.

Some electro-technologies are highly effective in helping customers manage their environmental responsibilities: reverse osmosis will clean up industrial waste streams; oxygen smelting can reduce industrial emissions of acid gases; plasma arc tools can cut primary metal industry emissions. When these technologies are adopted, customers and society benefit despite the fact that electricity demand may be increased as a consequence.

Social Impacts

Demand management programs also have social effects. Program-related employment will be created in communities across the province in many sectors including trades required to install and maintain energy efficiency equipment. The material supply and manufacturing sectors will need energy service specialists and personnel to develop and implement programs.

Total provincial employment is expected to be higher with the introduction of major demand management programs. The benefits created in any one community, however, may be lower than the direct impact of a major supply project. Demand management programs are unlikely to create significant local community impacts. Upgraded energy efficiency standards, building code amendments and electrical efficiency incentives may affect the type, cost, and pace of residential development.

Load shifting and efficiency improvement programs have other potential impacts. Time-of-use† rates will induce changes in how electricity is used by customers. Residential customers may change their pattern of household activities. Time of use, seasonal, and interruptible rates for industry may also result in changes to working hours.

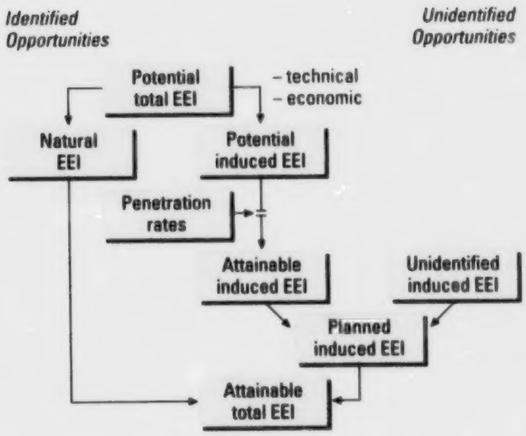
The substitution of high-efficiency equipment which provides the same energy service will have little or no impact on the lifestyles of Ontarians. Similarly, load shifting equipment such as storage water heaters which provide the same service (ie. adequate hot water when needed), will have no impact on lifestyles. Some efficiency measures such as caulking, insulation, and improved windows and doors may increase comfort in the home.

Electrical Efficiency Improvements – Potential and Attainable

Various estimates have been prepared for the technical potenial[†] of energy efficiency in Ontario. Technical potential is the reduction in electrical demand that could be achieved by a given year if all technically possible improvements were made throughout the province without regard for cost or people's preferences. In reality, of course, many improvements that are technically possible would be prohibitively expensive or otherwise undesirable. For example, while it might be technically possible to collect all less efficient refrigerators in Ontario and replace them with high efficiency ones, the costs and other disadvantages would clearly outweigh the potential improvements in electrical efficiency.

For these reasons, Hydro does not estimate technical potential in its demand management planning. Instead it uses estimates of potential total electrical efficiency improvements that take into account cost, timing, and opportunities.

Figure 7–3 **Electrical Efficiency Improvement Terminology**



It is extremely important to understand clearly the distinction between theoretical and realizable potential for energy efficiency improvement (EEI) in Ontario. Discussions of potential must include start and end dates in order to permit orderly calculation of the growth of capital stock and the replacement of existing stock. Figure 7–3 illustrates the concepts used in the development of this plan.

Potential Total EEI is the value that is obtained when mature technologies capable of improving electrical efficiency are matched with significant uses of electricity and subjected to the Total Customer Cost Test evaluation. Technical screening eliminates technologies that will not meet customers' needs and economic screening eliminates those with higher costs than supply options. This estimate of potential assumes 100% penetration of the market.

Estimates of the Potential Total EEI will vary depending on exactly what assumptions are made in the calculation of avoided costs and the completeness of the list of candidate technologies.

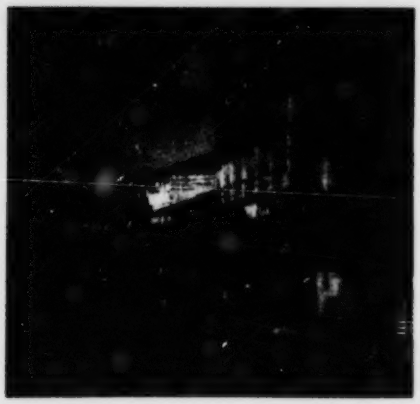
Hydro subdivides the Potential Total EEI into two parts:

- Natural electrical efficiency improvements are expected as a result of people's responses to normal market forces and the standard programs of governments. This continuing trend towards improved efficiency is captured in the Basic Load Forecast. Hydro's general information programs which promote electrical efficiency contribute to natural EEI.
- The balance of the total potential improvements is called Potential Induced Electrical Efficiency Improvements. These improvements are expected to require intervention by Ontario Hydro in the form of financial incentives to

decision-makers. This estimate of potential continues to assume 100% penetration of the eligible market.

Attainable Induced EEI is an estimate needed because the potential induced estimate ignores practical marketing considerations such as the availablity of efficient products, the presence of an infrastructure to supply and service these products, the willingness of decision-makers to accept them and impact of competitive response. Hydro's estimate of attainable induced efficiency improvements is developed from the estimate of Potential Induced EEIs and estimates of market penetration rates.

A Penetration Rate is defined as the percentage of the potential reduction that can be achieved for a specific demand management option by a specific year. These rates are based on assessments of the hurdles that have to be cleared to achieve success in the marketplace. Part of the process of determining the Demand Management Plan is to sketch out program concepts so that the practical considerations can be assessed for each market sector and technology.



The importance of insulation is constantly being reinforced.

[illegible]

Residential:	**2.6 million homes; 29% of electricity use**	
	Space & water heating;	**56%**
	Appliances;	**38%**
	Air Cooling;	**6%**
Commercial:	**600,000 businesses; 34% of electricity use**	
	Motors & equipment;	**39%**
	Lighting;	**38%**
	Space & water heating;	**11%**
	Air cooling;	**12%**
Industrial:	**18,000 customers; 37% of electricity use**	
	Motors & equipment;	**73%**
	Process heating;	**16%**
	Lighting;	**11%**

The estimate of the Attainable Induced EEI is based on identified opportunities and proven technologies. However, it is expected that new opportunities arising from emerging technologies and new ideas for increasing the penetration rates of current technologies will also contribute to the total reduction of load. The Unidentified EEI estimate provides an allowance of the expected reduction in power and energy demand arising from new ideas and emerging technology.

The Planned Induced EEI is the total reduction in power and energy expected as a result of Hydro's incentive-driven programs. It includes contributions from both identified and unidentified opportunities.

Measuring Net Program Impact

All demand management programs have built-in tracking and evaluation procedures. For example, keeping track of the number of efficient electric motors installed with incentives provides a physical basis for the estimation of program impact on electricity demand and the progress of the program against plan.

Corrections are applied to program tracking data to estimate the net impact of programs. These corrections include adjustments for:

- Free riders – customers who accept incentive payments for efficiency improvements they would have made anyway;
- Diversity† – not all customers will have their more efficient applications in full use at the same time;
- Coincidence – only a portion of a programs's electricity reduction will occur during periods of high demand (winter weekdays, 7:00 a.m. – 11:00 p.m.); and
- Power delivery losses.

Conservation Across the Province

Identifying demand management opportunities and developing effective programs also involves understanding where the growth in demand for electricity is occurring. Most electricity is consumed in Ontario's Golden Horseshoe which consists of Central Region and parts of Western Georgian Bay, and Eastern Regions, as shown in Figure 7-5. Areas of the province which do not have access to natural gas supplies also show a greater need for electricity service. Figure 7–6 shows electricity growth rates and the absolute level of increase in recent years in different areas of the province.

Ontario Hydro is promoting demand management throughout the Province.

Figure 7–5 **Where Electricity is Used in Ontario**

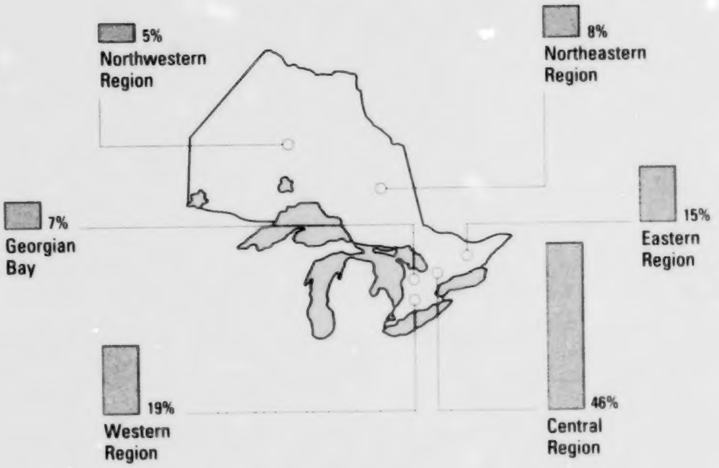
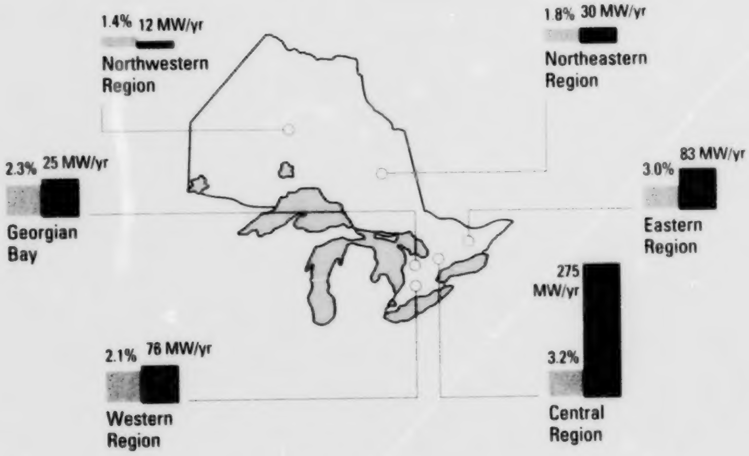

5%
Northwestern Region
8%
Northeastern Region
7%
Georgian Bay
15%
Eastern Region
19%
Western Region
46%
Central Region

Figure 7–6 **Growth in Primary Demand for Electricity by Region 1983-1987**


1.4% 12 MW/yr
Northwestern Region
1.8% 30 MW/yr
Northeastern Region
2.3% 25 MW/yr
Georgian Bay
3.0% 83 MW/yr
Eastern Region
275 MW/yr
3.2%
Central Region
2.1% 76 MW/yr
Western Region

Post-program audits are used to confirm that estimated program benefits have been achieved and will be sustained.

Data for contributions from demand management (in megawatts) in this chapter are:

- net of free riders;
- coincident with the power system's winter peak; and
- measured at the point of generation.

DEMAND MANAGEMENT OPPORTUNITIES

This section provides some details on demand management opportunities in three areas: electrical efficiency improvements, load shifting and peak clipping achieved through interruptible contracts. Using the year 2000 as a benchmark, the discussion quantifies attainable levels for each of these areas. A background report contains detailed analyses for the years 2000 and 2008.

To set the stage, some data are provided first about how, where and when electricity is used in Ontario, because this information is vital in assessing the opportunities in a particular sector or end use.

Electricity Use in Ontario

Ontario Hydro and municipal electric atilities serve about 3.3 million customers in three distinct market sectors:

- Residential – homes, cottages, farms
- Commercial – offices, condominiums, retail stores, restaurants, institutions, apartments
- Industrial – mining, processing, manufacturing

Figure 7–4 indicates that each sector consumes about one-third of the total electricity used in Ontario. But, total consumption is only a small part of the story, since electricity is used for a variety of purposes by customers in each sector.

Hydro is working to understand customer needs in each sector in order to design effective programs. While there are core customer expectations like reliability, low cost and environmental protection, the customer emphasis can vary among sectors. Residential customers want convenience, comfort and low cost. Commercial customers look for excellent customer service, reliability of supply and low cost. Industrial customers are particularly concerned about cost and reliability, and are always looking for ways to improve productivity and competitiveness.

Clearly, one or two demand management initiatives cannot capture the potential for demand reduction, given the diversity of end uses and customer needs. Hydro's aim is, therefore, to provide customers with a comprehensive set of programs covering all sectors and many end uses.

Market research, technology assessment and research, and preliminary field testing of program concepts are all part of Hydro's approach to identifying opportunities for and ensuring good results from demand management programs.

The remainder of this section is devoted to a discussion of demand management

[illegible]

	Residential	**Commercial**	**Industrial**
Efficient lighting	•	•	•
Appliances	•	•	
Water heater wrap, etc.	•	•	
Low-flow shower heads	•	•	
Building improvements			
Insulation	•	•	
Weather stripping	•	•	
R2000 building standard	•		
Window replacements	•		
Efficient design		•	
Heat pumps	•		•
Efficient HVAC systems		•	
Energy management systems		•	
Refrigeration		•	•
Individual metering		•	
High efficiency motors, compressors, fans, pumps		•	•
Industrial drives			•
Industrial processes			•
Electric steelmaking			•

[illegible]

System Avoided Cost (at 100% Load Factor)

	2.6¢/kWh	3.7¢/kWh	4.8¢/kWh
Residential	1,660	1,920	1,930
Commercial	1,890	2,480	2,820
Industrial	490	530	540
Total	4,040	4,930	5,290

[illegible]

		Penetration %	Expected Penetration MW	
Residential:	Renovations	3 – 20	50	
	Heat Pumps	15	25	
	R2000 or equivalent	25	145	
	Appliances	20 – 50	130	
				350
Commercial:	Offices	50	480	
	Retail	40	160	
	Apartments	50	140	
	Other	45 – 60	360	
				1,140
Industrial:	Motors & Equipment	45	140	
	Lighting	45	30	
	Other	30 – 50	70	
				240
Total for Identified Measures				1,730

[illegible]

		Peak Power (MW) Load Forecast			Energy (TWh) Load Forecast		
		Lower	Median	Upper	Lower	Median	Upper
Identified Attainable:	Residential	190	350	460	0.9	1.6	2.1
	Commercial	900	1,140	1,330	5.2	6.6	7.7
	Industrial	160	240	270	1.0	1.5	1.7
	Subtotal	1,250	1,730	2,060	7.1	9.7	11.5
Unidentified (all sectors):		350	270	440	0.9	0.3	1.0
Total Planned:		1,600	2,000	2,500	8.0	10.0	12.5

opportunities in each of the three major areas noted above:

- electrical efficiency improvements;
- load shifting; and
- capacity interruptible load.

Electrical Efficiency Improvement Opportunities

Figure 7–7 lists examples of technologies, which either individually or in combination, provide important opportunities for electrical efficiency improvements. These include improved insulation and lower infiltration levels in new and existing houses; heat pumps to displace resistance electric heating; improved heating and ventilation equipment in commercial buildings; high efficiency lighting; and high efficiency motors and variable speed drives.

In the practical application of an efficiency program, decision-makers have to be informed about the efficiency opportunity, as well as its cost and its performance. They must have confidence in the technology and in its value. It must represent a significant and desired improvement. The delivery channels and service infrastructure must be in place and where financial barriers exist, appropriate incentives must be available. It is important to keep in mind that the mere existence of a beneficial technology will not in itself guarantee a high rate of customer uptake.

As noted earlier, Hydro assesses efficiency improvement opportunities and classifies them as either likely to be adopted by customers through normal market forces (natural) or requiring active intervention by Hydro. Figure 7–8 shows Hydro's estimates of the Potential Induced EEI options to the year 2000 for the median load growth. These estimates are based on the assumption that no institutional or other barriers stand in the way of complete

Customers are encouraged to make more efficient use of their electrical appliances.

customer uptake. All estimates are based on use of efficient equipment and technology currently available in the marketplace.

The figure illustrates the sensitivity of this potential to three different levels of system avoided costs. These avoided costs define how much efficiency improvement can be achieved economically with incentive-driven programs. Thus, if the forecast of avoided costs were lower, the Potential Induced EEI in each sector would be lower, and vice versa.

The Potential Induced EEI in each sector represents the amount by which Hydro's Basic Load Forecast of peak demand would be reduced if the potential were achieved.

As the figure shows, the potential induced efficiency improvements across all sectors at the median load growth avoided cost of 3.7 cents/kWh is approximately 5,000 MW by the year 2000.

Potential in Alternative Plans

The System Avoided cost (3.7 cents/kWh) used in Figure 7–8 is the one used for the proposed plan. The Figure also shows plus and minus 30% variations on the 3.7 cents. It is the average value in the 2000 to 2014 time period for the median load growth. It is quoted at the generator level and does not include the specific allowance for the transmission costs and losses that were included in the screening of the EEI options. The cost quoted is a "representative" one. Each option's avoided cost was calculated using the energy savings pattern appropriate to that option. The avoided costs for the other candidate plans vary only slightly from the values for the proposed plan. The representative

Figure 7–11 A **Annual Load Shape and Daily Load Shape** Total System 1988

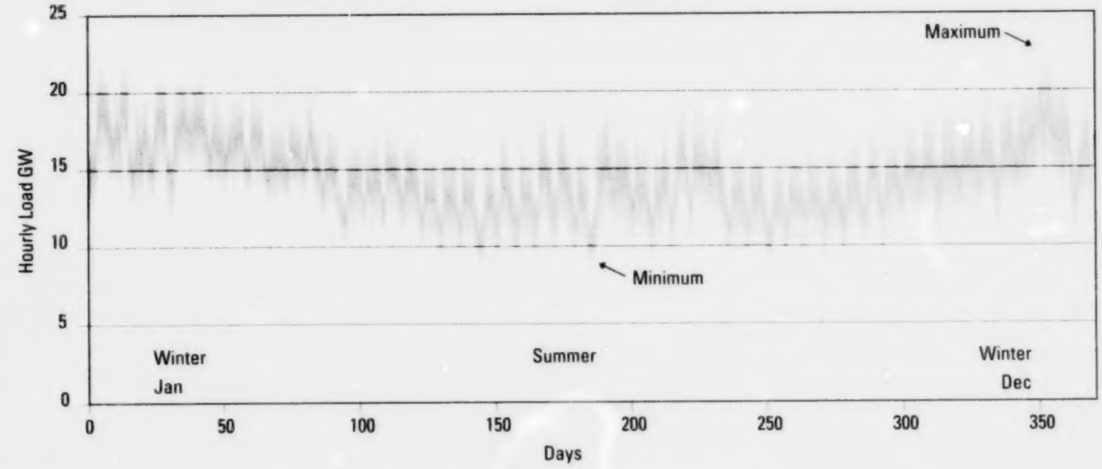
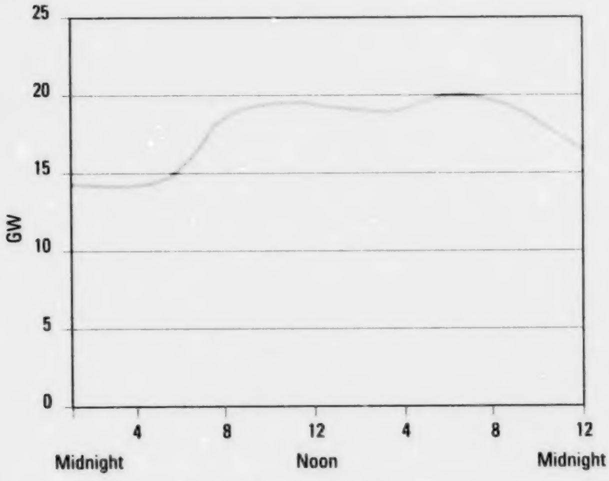


Figure 7–11 B **Daily Load Shape**



avoided cost for Plan 22 is slightly lower at 3.6 cents/kWh and for plan 24 higher at 4.2 cents/kWh. In light of the small changes these imply in the Potential Induced EEI, and the further reduction when attainability is considered, it was decided not to modify the demand management plan component in alternative candidate plans.

Comparison with Ministry of Energy

The Ontario Ministry of Energy (OME) recently commissioned Marbek Resource Consultants Ltd. and Torrie, Smith & Associates to, amongst other things, update an earlier report on the potential for electricity conservation in Ontario. They estimated what they describe as the "Maximum Economic Potential" for savings by the year 2000. Their estimate is 6,637 MW. This is at the end use level and includes natural potential that has been excluded from the estimates shown in Figure 7–8. When allowance is made for losses (approximately 8%), natural EEI (approximately 1600 MW), differences in the screening methodologies, and the general uncertainty associated with these estimates, the two sets of results are not inconsistent.

It should be noted that the OME report does not address the question of the proportion of the economic potential that is practically attainable.

Attainable EEI

When the Attainable Induced EEIs are estimated, it is assumed that financial incentives will be set high enough to motivate the marketplace to adopt the efficiency improvements. A guiding principle affecting estimates of market penetration and incentive levels is a requirement that customers who benefit must also make a financial contribution to the cost of implementing the improvement in question. The size of the contribution depends on the program. In some cases, an incentive of 20% of the extra capital cost of an efficiency upgrade may be enough to motivate the customer. In other cases, it may be necessary for Hydro to pay 80% of the incremental cost.

Expected customer uptake is based on Hydro's experience with demand management, as well as an examination of comparable programs undertaken by American electrical utilities. These suggest that market penetrations of between 3% and 55% of eligible customers will be achieved by incentive-driven demand management programs. Figure 7–9 shows the expected level of customer acceptance, and attainable megawatt reductions expected to the year 2000 from mature technologies.

Planned Induced EEI

These estimates have been supplemented with an estimate of the likely contribution from new ideas to increase the penetration rates, and the expected new opportunities arising from emerging technologies. Figure 7–10 shows the planned results of incentive-driven efficiency improvements and the resulting reduction in overall demand across the load forecast bandwidth.

Hydro considers that an efficiency improvement level of 2,000 MW and 10.0 TWh by the year 2000 is appropriate and realistic for incentive-driven programs. This level assumes that load growth will follow the median forecast. If load growth is higher or lower than expected, then the planned level is changed to reflect the changed system economics and market opportunities.

Hydro has set these plan levels recognizing that it is important to be realistic. If they are set too high, the proper balance of economic demand and supply measures will not be achieved and customers will experience higher costs and greater risk of unsatisfactory reliability. If they are set too low, Hydro would over-invest in supply facilities and customers' costs would be higher than necessary.

As has been described in Chapter 6, planning is an iterative process. The planned results presented in this document were derived using avoided cost estimates pre-dating the Demand/Supply Plan. The estimates of the Attainable Induced EEI (Figures 7–9 and 7–10) are based on the avoided cost for the Proposed Plan. A judgment has been made that the changes in the estimates of identified potential do not merit changing the planned amounts. The Unidentified Induced EEI, shown in Figure 7–10 provides the balance between identified and the planned amounts.

Figure 7–12: System Potential for Load Shifting by Year 2000

Load Growth	Load Shifting
Lower	800 MW
Median	1,000 MW
Upper	1,200 MW

[illegible]

Customer Class	MW Peak Demand Reduction
Residential	254
General, <5 MW demand	412
General, >5 MW demand	133
Direct Industrial	366
Total	1,164

Figure 7–14 A **Peak Demand Reduction – Median Load Growth**

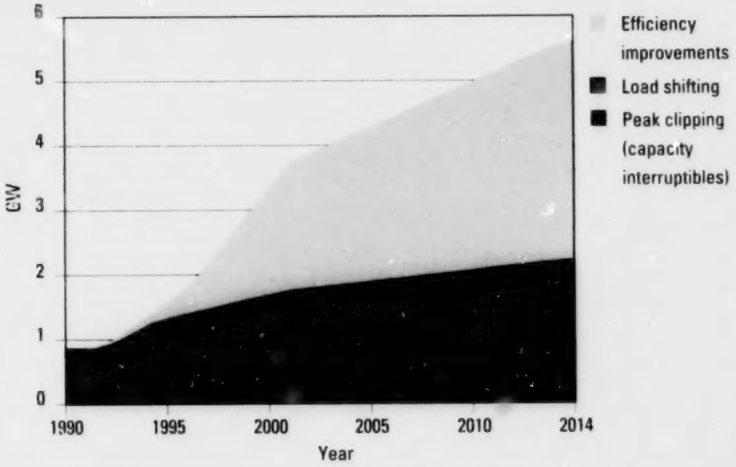
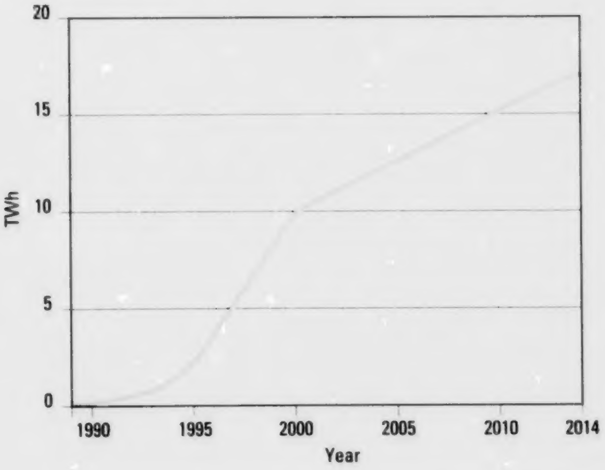


Figure 7–14 B **Energy Reduction – Median Load Growth**



As noted earlier, Hydro's demand management plan for efficiency improvements compares favourably with the plans and experience of leading North American utilities.

Load Shifting Opportunities

Although demand for electricity fluctuates from minute-to-minute, there are some general patterns – known as load shapes. Demand is higher through the day than at night, and higher in winter and summer than in spring and fall. Figure 7–11 shows a typical load shape for a full year, as well as for a winter day.

Since electricity cannot be stored, power stations have to be brought on and off line as required to meet these fluctuations in demand. By flattening electricity demand, Hydro can use generating stations more economically and reduce the need for new generation capacity. Load shifting, thus, has an important role in demand management.

Load shifting results in lower peak demands on the system. It does not, however, reduce energy demands since the energy displaced will normally be supplied in an off-peak period.

There are several ways to shift customer demand from peak to off-peak periods. Time-of-use (TOU) rates give customers an incentive to shift their electricity use away from peak demand periods when rates are higher. A utility can also control demand directly by means of devices that temporarily shut off electrical equipment like water heaters without inconvenience to the customer. Hydro's strategy is to rely primarily on time-of-use rates and deploy direct control[†] methods where they are economic and to the extent rate incentives do not fully achieve the desired results.

Most such load-shifting opportunities are linked to the daily cycle in the system load, rather than peaks occurring across the longer

Customized programs are developed to meet the needs of energy intensive agricultural operations.

weekly and seasonal cycles. There are few technologies that offer the potential to shift customer use from weekdays to weekends, or from winter to summer, compared to the potential that exists for shifting from daily peak to off-peak periods.

The opportunity to reduce peak demands is most dependent on the characteristics of the load about the time of the system peak demand, typically a cold January day – and the characteristics of the existing generating system. For Ontario Hydro, the useful potential for load shifting is estimated to be about 1,000 MW by the year 2000.

Beyond this amount there is little advantage to load shifting, since capacity requirements would not be reduced. That is because the daily load shape in the winter months is already very flat, with an 88% load factor.

While 1,000 MW is a reasonable level to set for load shifting by the year 2000 under the median load forecast, the level changes with load growth conditions, as shown in Figure 7–12.

Time-of-Use Rates

Beginning January 1989, time-of-use rates were applied to Hydro's large industrial customers, large customers of the municipal utilities and on an optional basis to municipal utilities. In 1990, over 250 large customers and 160 municipal distributors will be billed on time-of-use rates, representing over 80% of Ontario Hydro's total load and 95% of sales to municipal utilities.

The primary goal of time-differentiated rates is to have prices reflect costs more accurately. The motivation for this is a desire to be fair to all customers, as well as to encourage the efficient use of resources.

Figure 7–15 **Demand Management Plan – Peak Power Reduction (MW)**

		Load Forecast		
		Lower	Median	Upper
1994:	Electrical Efficiency Improvement	482	633	743
	Load Shifting	400	560	620
	Capacity Interruptible Load*	558	632	696
		1,440	1,825	2,059
2000:	Electrical Efficiency Improvement	1,600	2,000	2,500
	Load Shifting	800	1,000	1,200
	Capacity Interruptible Load*	599	702	798
		2,999	3,702	4,498
2014:	Electrical Efficiency Improvement	2,475	3,400	4,250
	Load Shifting	1,080	1,280	1,480
	Capacity Interruptible Load*	771	890	976
		4,326	5,570	6,706

** 1988 capacity interruptible load was 763 MW. Net reduction by 2014 is 4807 MW for the median forecast.*

Figure 7–16 **Demand Management Plan – Sectoral Breakdown (Median Growth)**

		Sector					
		Residential		Commercial		Industrial	
		MW	TWh	MW	TWh	MW	TWh
1994:	Electrical Efficiency Improvement	192	0.8	317	1.9	148	0.8
	Load Shifting	0	0	210	0	350	0
	Capacity Interruptible Load	0	0	0	0	632	0
2000:	Electrical Efficiency Improvement*	500	1.8	1,140	6.6	360	1.6
	Load Shifting	80	0	360	0	560	0
	Capacity Interruptible Load	0	0	0	0	798	0
2014:	Electrical Efficiency Improvement*	985	3.5	1,725	10.0	690	3.5
	Load Shifting	110	0	460	0	710	0
	Capacity Interruptible Load	0	0	0	0	967	0

** Includes Unidentified EEI allocated 55/45 to residential and industrial.*

Time-of-Use rates encourage customers to:

- shift load to off-peak times;
- reduce loads at peak times; and
- schedule new loads for off-peak times (valley filling).

The main effect of time-of-use rates is expected to be load shifting. For example, industrial customers can take advantage of TOU rates by charging battery-driven equipment at night.

Figure 7–13 shows that the expected load shifting response by the year 2000 could exceed the amount the electricity system could use effectively, if time-of-use rates were applied to all customer classes. This figure is based on experiments conducted in recent years. It assumes no financial incentives will be given to customers other than the time-differentiated rates themselves. The cost-effectiveness of time-of-use rates and associated metering may not justify the extension of time-of-use rates to customers with small loads.

In addition to time-of-use rates, Hydro is offering customers a Thermal Cool Storage program which uses incentives to encourage commercial customers to install equipment which uses ice or chilled water produced during off-peak hours to cool large office buildings during the day.

Direct Load Control

An alternative to influencing customer decisions through price signals is direct control of specific customer loads. Water heaters and space heating are the prime candidates. Special equipment would be needed in the form of larger tanks or special storage furnaces. In some applications, the most economical way to provide customers with savings and Ontario Hydro with load shifting may be to use direct load control rather than time-of-use rates.

Providing incentives to reduce financial barriers to efficiency improvements.

The combination of time-of-use rates, incentive-driven initiatives like the Thermal Cool Storage programs, and direct load control measures are expected to shift as much load off the daily peak as the power system can use.

Capacity Interruptible Load (CIL) Opportunities

Hydro offers capacity interruptible contracts for customers willing to trade reliability for lower electricity bills. Under an interruptible contract customers agree to reduce their load to a stipulated level on request from Ontario Hydro. Requests to cut load would be made at times of supply limitation on the power system (peak clipping), and are limited in frequency and duration by contract conditions. Interruptible customers receive a discount on their electricity rates based on the amount of contracted interruptible load.

The total capacity value of current interruptible load contracts is about 1,000 MW. Hydro's planning recognizes, however, that not all interruptible customers would be consuming electricity at their contract maximums when cuts might be called for. After taking this into account, it is estimated that about 600 MW of reliable load reduction can be achieved in the event of inadequate supply.

The forecast amount of capacity interruptible load is 702 MW (after allowing for diversity)

Figure 7-12: Residential Sector Plan

Plan (1990–94):	OM&A		$143 million		
	Incentives		$184 million		
Electrical Efficiency	1990	1991	1992	1993	1994
Audits	●	●	●	●	●
Renovation advisory service	●	●	●	●	●
High Efficiency replacement upgrades	●	●	●	●	●
Water heater blanket	●	●	●	●	●
R2000 homes	●	●	●	●	●
EE housing standard	●	●	●	●	●
Efficient Appliances	●	●	●	●	●
Heat recovery ventilation	●	●	●	●	●
Barn lighting & heating	●	●	●	●	●
Barn energy management	●	●	●	●	●
Hi Eff Sentinel lights	●	●	●	●	●
Efficient lighting	●	●	●	●	●
Seasonal to year-round conversion advisory	●	●	●	●	●

Load Shifting	
TOU Rates	May be implemented by municipal utilities if the metering and associated billing is cost-effective.
Direct Load Control	May be implemented as a contingency if TOU rates for industrial and commercial customers do not yield sufficient load shifting.

by the year 2000, assuming median load growth conditions; 599 MW assuming the lower growth; and 798 MW assuming the upper growth.

In recent years there has been an increase in the number of contract cancellations by customers who perceive that the reliability of supply is likely to decline with a corresponding increase in the frequency of interruptions. At the same time, other customers have been increasing the amount of load under contract.

Overall, Hydro is forecasting that the amount of interruptible load under contract will continue to grow at the same rate as the industrial sector load. If reliability deteriorates significantly, the amount of interruptible load contracted can be expected to grow at a slower rate or even decrease. Projecting CIL to grow at the same rate as other industrial load assumes reliability will not change significantly or that interruptible rates will be adjusted to maintain customer benefits.

Some adjustment to this growth is needed because some customers with capacity interruptible contracts may take advantage of time-of-use rates to shift load and reduce their contracts. Still other customers may be installing cogeneration capacity, with a similar effect on interruptible load growth.

Nevertheless, interruptible rates are expected to continue to play a significant role in deferring the need for new major supply and in helping to assure the reliability of supply to firm loads.

Plan Levels

In total, the Plan calls for over 3,000 MW of peak power demand reduction by the year 2000, through capacity interruptible contracts and the use of programs for electrical efficiency improvements and loadshifting. Planned levels for peak demand reduction are shown in Figure 7-14.

Figure 7-15 shows the levels for peak reduction for selected years for the load growth bandwidth, while Figure 7-16 provides a breakdown of peak power and energy reduction levels by sector for the median load growth case.

Comparison With US Targets

In June, 1989, Ontario Hydro commissioned an independent expert review of demand management targets. This study* was a comparative survey of demand management targets among large North American utilities. It was designed to determine how realistic and ambitious the Ontario Hydro targets are.

* ("Independent Consultant Review of Ontario Hydro Expectations and Targets for Demand Management Activities, Third Report," RCG/Hogler, Dailly, Inc. August 14, 1989)

Over 50 of the largest North American utilities (including 51 US and 3 Canadian) were surveyed. Less than 30 had serious demand management programs with specific targets. The results showed Ontario Hydro's targets to be among the leaders in absolute (MW) terms. In relative terms, the targets for 1995 are in the middle of those utilities having serious targets. Ontario Hydro's targets are second only to Duke Power for the year 2000.

The main conclusions of the consultants are:

- Ontario Hydro targets are ambitious in relative and absolute terms, especially for the year 2000.
- The demand management savings are programmed to occur over a compressed time period.
- Proposed Ontario Hydro programs have good sectoral balance and diverse end-use focus.
- To achieve its overall goals, Ontario Hydro must simultaneously deploy a fairly large number of programs, each of which must meet its target, if overall system targets are to be realised.

Strategy for the Delivery of Demand Management

In 1989, Hydro kicked off Phase II of its energy management strategy with incentives supporting load shifting and a wide range of electrical efficiency programs (see Figure 7-2). Over the next few years the array of programs will broaden, developing into a complete portfolio of programs aimed at increasing customer value and decreasing the rate of growth of electrical demand. Ontario Hydro plans to spend of about $1 billion over these five years for program development and delivery, and R&D work required to support Plan initiatives to the year 2000.

Figure 7-18 Commercial Sector Plan

Plan (1990–94):	OM&A		$118 million		
	Incentives		$ 99 million		
Electrical Efficiency	**1990**	**1991**	**1992**	**1993**	**1994**
34 W fluorescent	•	•			
Compact fluorescent	•	•	•	•	•
Lighting redesign	•	•	•	•	•
Streetlight pilot	•				
Streetlighting4	•	•	•	•	•
EE ballasts		•	•	•	•
EE luminaires			•	•	•
T-8 lighting			•	•	•
Electronic ballast					•
Daylighting control					•
Heat pumps	•	•	•	•	•
Savings by design	•	•	•	•	•
Occupancy sensors	•	•	•	•	•
Air sealing/balancing		•	•	•	•
Grnd source heat pump		•	•	•	•
Cogeneration		•	•	•	•
Submetering			•	•	•
Building automation			•	•	•
Thermal envelope			•	•	•
Audits	•	•	•	•	•
Energy Service Co's	•	•	•	•	•
Individual metering	•	•	•	•	•
Architectural designs					•
Shower heads	•	•	•	•	•
Motors	•	•	•	•	•
Refrigeration		•	•	•	•
Cook/ Chill				•	•
Appliances	•	•	•	•	•

Figure 7-18 Commercial Sector Plan (continued)

Load Shifting	**1990**	**1991**	**1992**	**1993**	**1994**
Thermal Cool Storage	•	•	•	•	•
Thermal Heat Storage			•	•	•
60 gal wtr heater test	•				

Direct Load Control	May he introduced for water heating in the Offices segment in 1991; to be implemented as a contingency if time-of-use rates do not yield sufficient load shifting.
TOU Rates	Progressive implementation of TOU rates for large commercial customers is expected.

Figure 7-19 Industrial Sector Plan

Plan (1990–94):	OM&A	$147 million
	Incentives	$ 34 million

Electrical Efficiency	**1990**	**1991**	**1992**	**1993**	**1994**
HE motors	•	•	•	•	•
EE lighting	•	•	•	•	•
Energy monitoring	•	•	•	•	•
Customized rebates	•	•	•	•	•
Load Shifting					
Off-peak charging	•	•	•	•	•
Load controls	•	•	•	•	•
Off-peak pulping		•	•	•	•
Off-peak melting		•	•	•	•
Interruptible Load	•	•	•	•	•

Strategies have been established for each of the three market sectors – residential, commercial and industrial. Within each sector, programs are designed to meet the specific needs of customers and are based on a number of program strategies.

General Program Strategies

- Working with municipal utilities and the MEA to develop and deliver an effective portfolio of demand management programs;
- Using customized audits, as well as market and demand management research, to define efficiency improvement opportunities and market barriers, and to determine where incentives are necessary to implement such opportunities;
- Extending customer contacts to increase the visibility of energy management efforts;
- Placing a high priority on accelerated development and testing of efficient electric products to ensure their availability for use in programs;
- Building a broader base of customer understanding and acceptance of energy efficent products and lifestyles.
- Designing programs with flexibility to respond to changes in load growth and to changes in the market place;
- Developing and delivering a broad portfolio of programs so that customers can choose programs that best suit their individual needs;
- Integrating programs into the existing package of customer services now offered by Hydro and municipal utilities (e.g., energy information, customer advice, major accounts service, cost-sensitive rate structures, rate design reform and helpful billing information);
- Seeking opportunities for the private sector (energy consultants, architects, contractors) to assist Hydro and the municipal utilities in program delivery;

- Using pilot programs to limit risks in untested program concepts; and,
- Providing incentives to reduce financial barriers to efficiency improvements.

Residential/Agricultural Program Strategies

- Developing customized programs to meet the specialized needs of energy-intensive agricultural operations;
- Working with government and standards-setting bodies to raise electrical efficiency standards for appliances and energy efficiency in building codes;
- Ensuring residential customer programs are highly visible to raise public awareness of the need and opportunities for efficiency improvements; and,
- Developing programs to cover many end uses and customer segments.

Commercial Program Strategies

- Increasing electrical efficiency in all segments;
- Targeting programs for delivery to large existing customers in the largest regions (Central, Eastern and Western), and to the largest utilities;
- Achieving maximum impact by increasing staff available for both proactive and reactive customer contacts;
- Accrediting utilities, distributors and contractors for particular incentive initiatives in order to increase the leverage of Hydro's regional resources; and,
- Using training, research and service to strengthen delivery channels and expand relationships with allies;

[illegible]

Plan (1990–94):	OM&A	$150 million

- Long-range product R&D
- Long-range program concept assessment
- Enhancement of end-use load forecasting models and databases
- Enhancement of screening models and methods
- Development of administrative systems
- Promotion of higher standards for buildings and electrical equipment
- Improvement of relationships with allies and major customer organizations
- Coordinated demand/supply planning

[illegible]

Electrical Efficiency Improvement — **Load Forecast**

	Lower		Median		Upper	
Year End	**MW**	**TWh**	**MW**	**TWh**	**MW**	**TWh**
2000	1600	8.0	2000	10.0	2500	12.5
2014	2475	12.4	3400	17.0	4250	21.2

Load Shifting

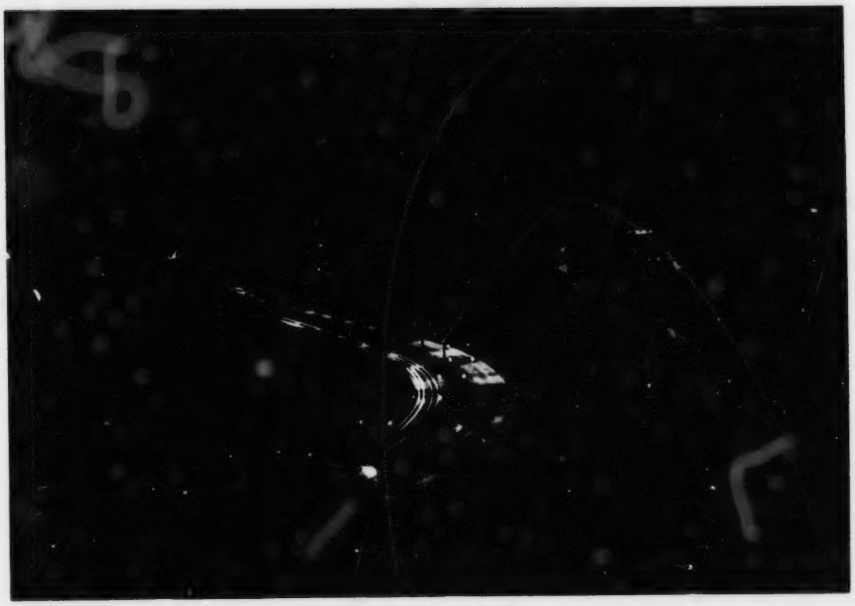
	Lower		Median		Upper	
Year End	**MW**	**TWh**	**MW**	**TWh**	**MW**	**TWh**
2000	800	0	1000	0	1200	0
2014	1080	0	1280	0	1480	0

Capacity Interruptible Load

	Lower		Median		Upper	
Year End	**MW**	**TWh**	**MW**	**TWh**	**MW**	**TWh**
1988			763(actual)			
2000	599	0	702	0	798	0
2014	771	0	890	0	976	0

Industrial Program Strategies

- Employing a dual strategy to attract those customers most likely to adopt electrical savings measures. Immediate results will be pursued with medium and smaller customers; selected large customers are targeted to obtain large MW reductions over the long-term;
- Tailoring programs to meet the special needs of large customers; using general programs for smaller businesses;
- Overcoming barriers through the intensive use of audits and subsidized feasibility studies to help customers assess load shifting and efficiency improvement opportunities;
- Making moderate use of incentives in programs: tailored for large customers, standardized for smaller customers;
- Encouraging customers to get maximum value from TOU rates through substantial information and technical support;
- Assisting allies' efforts to market efficient products and processes through support of demonstrations and case studies; heavy use of information packages for allies and utilities;
- Personal selling of electrical efficiency and load shifting to large customers by Regions staff; relying on and assisting allies to influence smaller customers; and,
- Assisting trade and technical associations in training and education related to electrical efficiency improvements.



Substituting high efficiency lights in municipalities is an important demand management program.

The industrial sector accounts for 35% of the electricity used in the province.

Demand Management Action Plan

Over the next five years and beyond, Hydro's plan is to get the greatest reduction in load growth that can be accomplished economically through efficiency improvements, load shifting and capacity interruptible load contracts. The plan levels are not ceilings – if it is possible to exceed them, Hydro will do so.

Program initiatives planned for 1990–94 are listed in Tables 7–17 to 7–20. While many programs are shown to start in 1990 and continue to 1994, the intensity of program delivery will grow rapidly through the period. Payment of incentives is planned to increase from $28 million in 1990 to $124 million in 1994.

Conclusion

The Demand Management Plan contains initiatives for load reduction through electrical efficiency improvements, load shifting through time-of-use rates and direct load control, and peak clipping through capacity interruptible load contracts. The planned levels to the years 2000 and 2014 are shown in Figure 7–21. Year by year data are shown in Figure 7–22. Under the median load forecast, demand management programs are expected to be contributing a total of 3,702 MW by the year 2000 and 5,570 MW by 2014.

These results will be achieved through programs designed to help customers make informed decisions about electricity use and provide incentives where needed to overcome barriers. The Plan's success will depend on the active support of municipal utilities, electrical industry allies and customers.

Hydro's Demand Management Plan is realistic and challenging.

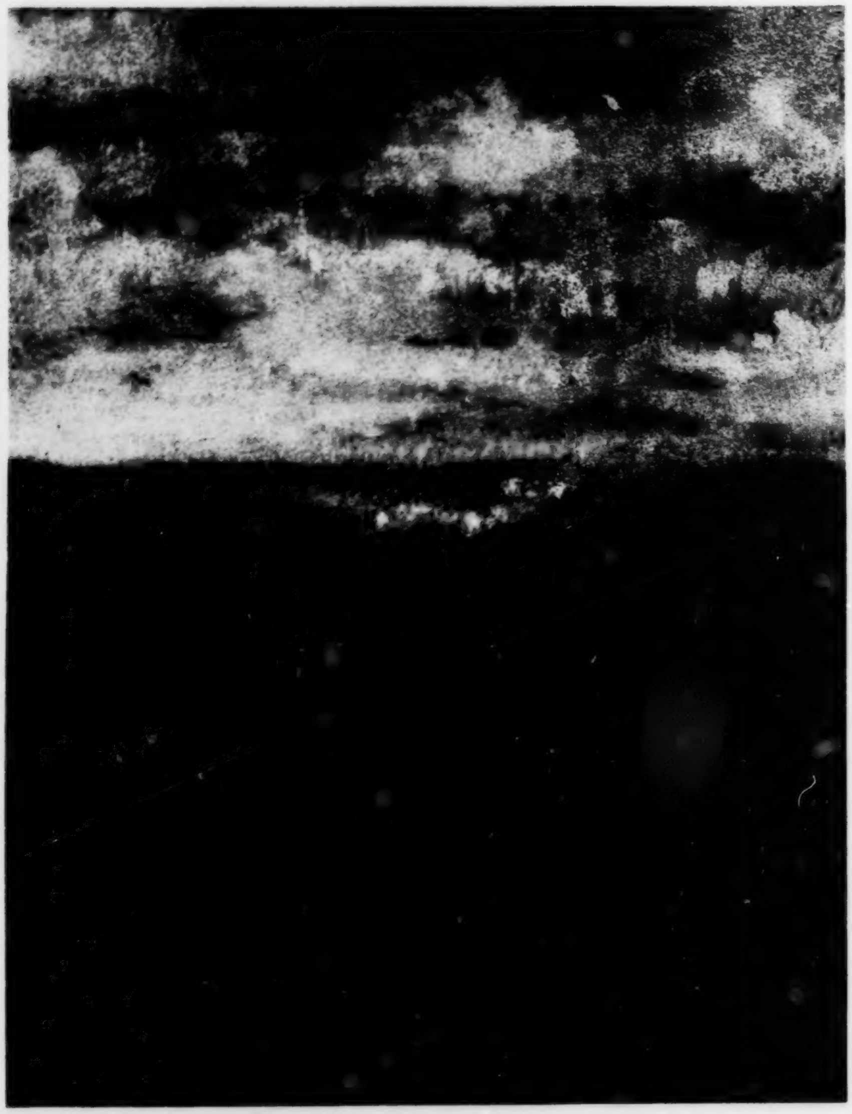
[illegible]

			Lower Load		
	EEI	EEI	LS	CIL	Total
Year	(MW)	(GWh)	(MW)	(MW)	(MW)
1989	14	70	78	709	801
1990	36	180	161	599	796
1991	62	310	246	583	891
1992	101	505	387	566	1054
1993	146	730	519	554	1219
1994	251	1255	576	558	1385
1995	400	2000	620	561	1581
1996	640	3199	663	566	1869
1997	880	4399	707	573	2160
1998	1120	5598	749	580	2449
1999	1360	6798	790	587	2737
2000	1600	7997	800	599	2999
2001	1663	8312	820	607	3090
2002	1725	8622	840	616	3181
2003	1788	8937	860	625	3273
2004	1850	9246	880	633	3363
2005	1913	9561	900	643	3456
2006	1974	9872	920	655	3549
2007	2038	10186	940	668	3646
2008	2100	10496	960	682	3742
2009	2163	10811	980	697	3840
2010	2225	11121	1000	713	3938
2011	2288	11436	1020	727	4035
2012	2350	11746	1041	742	4133
2013	2412	12055	1060	756	4228
2014	2475	12372	1080	771	4326

** The Electrical Efficiency Improvement and Load Shifting forecasts for 1989-2000 are based on the Load Forecast of 19881212*

Figure 7-22 Demand Management Plan (continued)
Cumulative Values

Median Load					Upper Load				
EEI (MW)	**EEI (GWh)**	**LS (MW)**	**CIL (MW)**	**Total (MW)**	**EEI (MW)**	**EEI (GWh)**	**LS (MW)**	**CIL (MW)**	**Total (MW)**
14	70	81	735	830	14	70	84	758	856
45	224	171	632	848	56	280	180	658	894
78	390	266	625	969	98	490	282	660	1040
126	630	423	621	1170	158	790	455	660	1273
183	914	582	623	1388	229	1145	735	672	1636
314	1569	656	632	1602	393	1964	728	696	1817
500	2499	717	641	1858	625	3124	795	705	2125
800	3999	776	652	2228	1000	4998	870	724	2594
1100	5498	836	664	2600	1375	6872	946	744	3065
1400	6998	893	676	2969	1749	8747	1017	765	3531
1700	8497	946	688	3334	2125	10621	1100	782	4007
2000	9997	1000	702	3702	2500	12495	1200	798	4498
2100	10496	1020	712	3832	2624	13120	1220	811	4655
2200	10996	1040	724	3964	2750	13745	1240	826	4816
2300	11496	1060	737	4097	2875	14370	1260	841	4976
2400	11996	1080	749	4229	3000	14995	1280	857	5137
2500	12495	1100	762	4362	3125	15620	1300	871	5296
2600	12995	1120	775	4495	3250	16244	1320	884	5454
2700	13495	1140	788	4628	3375	16869	1340	896	5611
2800	13995	1160	802	4762	3500	17494	1360	907	5767
2899	14495	1180	816	4895	3625	18118	1380	917	5922
3000	14995	1200	830	5030	3750	18743	1400	928	6078
3101	15494	1221	844	5166	3875	19368	1420	940	6235
3200	15994	1240	859	5299	4000	19993	1440	951	6391
3298	16487	1260	874	5432	4123	20608	1460	963	6546
3400	16995	1280	890	5570	4250	21244	1480	976	6706



8 THE NON-UTILITY GENERATION PLAN

Non-utility generation (NUG) is electrical generation owned and operated in Ontario by electricity producers other than Ontario Hydro. Ontario Hydro is giving non-utility generation a high priority and it forms a significant part of Hydro's integrated plans.

As such, contributions from economic non-utility generation are factored into the planning process at an early stage.

This chapter examines the potential for non-utility generation in Ontario, and the factors related to this potential, and presents Ontario Hydro's Non-Utility Generation Plan. The NUG Plan outlines the expected electricity contributions from the non-utility generators for the 25-year planning period considering both purchase generation and load-displacement generation.

In Ontario, NUG provides additional electricity through renewable hydraulic generation, use of waste fuels and energy efficient co-generation. Because of the relatively small scale of many NUG projects, they can be built in a short time and can be adapted to local conditions. Furthermore, private sector producers take on some of the development and financing risks associated with electrical generation projects.

Hydro's Current Activities

Hydro established a Non-Utility Generation Division responsible for promoting economic non-utility generation in Ontario. Although this type of generation is not new to Ontario, Hydro's policy gives it much greater emphasis now than it has in the past, especially where such generation is produced from renewable or waste resources, or at high efficiency. As part of its promotional activities, Hydro conducts an annual workshop with non-utility generators, provides technical and financial assistance to qualifying developers and participates in several committees in order to encourage the NUG industry.

For non-utility generators with capacities up to 5 MW, Hydro will purchase electricity at both flat and time-differentiated rates, under standard contract conditions. Special contract conditions may be negotiated at the request of the generator to help meet the specific needs of individual projects.

For NUG projects with capacities greater than 5 MW, Hydro purchases the electricity at rates up to avoided cost. To streamline and standardize the treatment of these projects, Hydro has established a structured solicitation process for generation capacity, as described later in this chapter.

CURRENT NUG STATUS

As of January 1989, the estimated capacity of non-utility generation in service in Ontario was 1,288 MW. Of this total, 26 MW is classed as purchase generation. The remainder is load-

NUG Concepts

Non-utility generation (NUG) is electrical generation owned and operated in Ontario by electricity producers other than Ontario Hydro. Non-utility generators include private and municipal utilities, and private power producers. The electricity they generate may be either purchased by Hydro for distribution to its customers, or else used to meet the producer's own electricity needs.

Non-utility generation which is sold to Hydro is known as "purchase" generation. The generators involved are interconnected with the province-wide transmission and distribution network. Like purchases from other utilities, purchase generation is considered to be a supply option.

On the other hand, non-utility generation which supplies electricity to meet the producer's own needs, or is directly purchased by a customer other than Hydro is referred to as "load-displacement" generation. It is so termed because such generation displaces load which Hydro would otherwise have been responsible for supplying.

In assessing the contribution of non-utility generation to meeting Ontario's electricity requirements, it is useful to categorize the generation involved according to the primary energy and energy conversion process. As indicated in Figure 8–1, non-utility generation uses three different primary energies: falling water; conventional fossil fuels, chiefly natural gas; and waste fuels, chiefly wood waste, landfill gas (LFG) and municipal solid waste (MSW).

NUG projects are also categorized in terms of the three different generation processes in common use. These are hydraulic, cogeneration and other thermal processes.

Cogeneration is a process in which generators simultaneously produce electricity and process heat for other energy applications. Cogeneration makes efficient use of fuel, thereby helping the cogenerator get the most value from the energy input and improving the competitive position of Ontario industries. Cogeneration uses either fossil fuels such as natural gas or coal, or waste fuels such as wood waste and spent pulping liquor.

Figure 8–1 NUG Primary Energy and Conversion Processes

Conversion Process	Primary Energy Falling Water	 Natural Gas	 Energy-From-Waste
Hydraulic	•	–	–
Cogeneration	–	•	•
Other Thermal	–	•	•

displacement generation, most of which has been in-service for many years. Current purchase and load-displacement non-utility generators in service and their capacities are provided at the end of this chapter in Figures 8–11 and 8–12.

The contribution of the various NUG primary energies and conversion processes to Ontario's electricity supply is noted in Figure 8–2.

As with major supply facilities, NUG projects eventually reach the end of their service lives and have to be retired. Between now and the year 2000, it is estimated that NUG facilities representing some 200 MW will be retired from service.

Purchase Generation

As of January 1989 there were 24 purchase generation facilities in service with a total capacity of 25.6 MW. Two of these projects account for 43% of the installed capacity, with the other 22 projects making up the remaining 57%.

The year-to-year growth in purchase generation capacity in megawatts (MW) and energy in terawatt hours (TWh) are shown in Figure 8–3 and Figure 8–4 respectively. During 1987, purchase generators supplied Hydro with 0.075 TWh of electricity. This amount increased by 25% to 0.094 TWh in 1988.

Although the current levels of purchase generation are relatively low, a number of new projects are at various stages of implementation and negotiation.

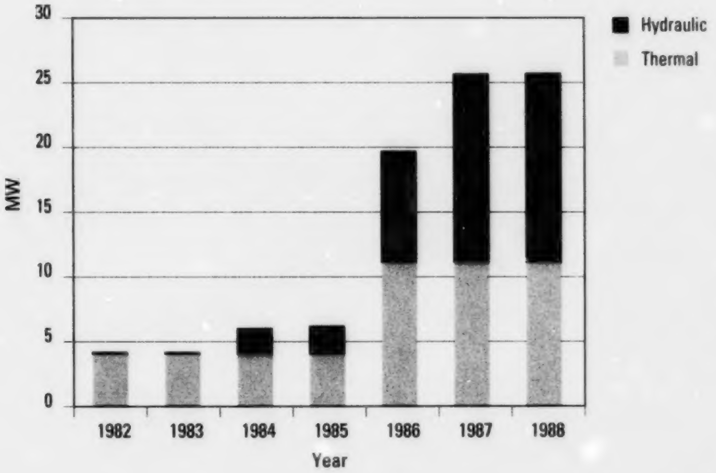
Load-Displacement Generation

As of January 1989, the bulk of Ontario's non-utility generation was load-displacement generation. There are over 60 customer facilities

Figure 8–2 **Installed NUG Capacity (MW) – January 1989**

Conversion Process	Primary Energy Falling Water	Natural Gas	Coal/ Diesel	Energy-From-Waste
Hydraulic	702	–	–	–
Cogeneration	–	438	80	54
Other Thermal	–	6	4	4
Total	702	444	84	58
% of Grand Total	55%	34%	6%	5%
Grand Total = 1,288 MW				

Figure 8–3 **Purchase NUG Capacity In-Service**



currently in-service, with a total installed capacity of about 1,262 MW.

The installed NUG capacity is evenly split between hydraulic and thermal generation. During 1988, these generators produced a total of about 5 TWh of electricity, or roughly 4% of the total electrical generation in the province. Some of these generators occasionally sell electrical energy to Hydro. This is done at their own discretion, when particular generators are producing more electricity than they need. These "at-will" sales of surplus power amounted to 0.07 TWh in 1988. Figure 8–4 breaks down the overall NUG energy growth trend into purchase contracts and at-will sales.

FACTORS INFLUENCING NUG POTENTIAL

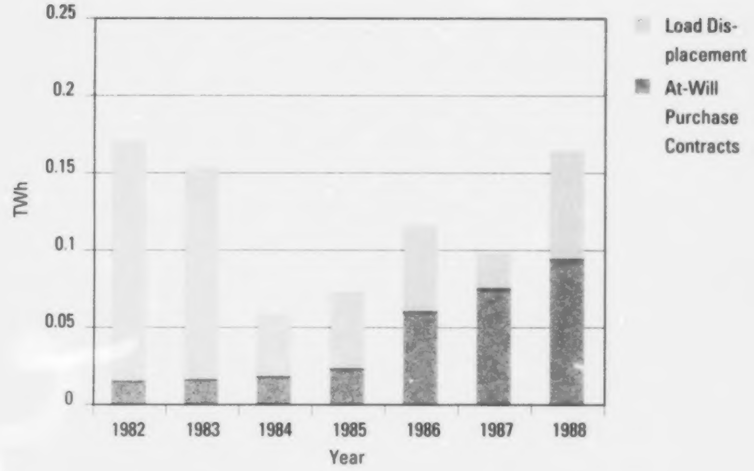
The development of non-utility generation reflects marketplace forces and their impact on profitability. All the factors outlined in this section have a role to play in the development of Ontario's NUG industry.

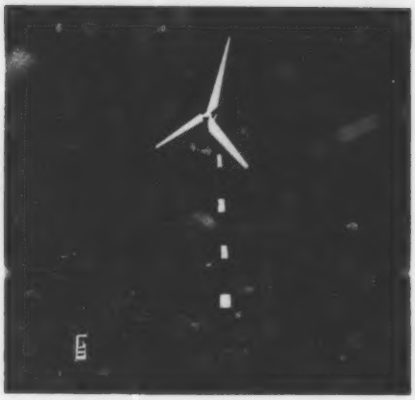
Rate of Return on Investment

Non-utility generation must be profitable or else potential investors will look elsewhere. Therefore, achieving an acceptable rate of return on investment is the first and most critical factor affecting the viability of a non-utility generation project. Based on past experience, it appears that rates of return on investment in the range of 15% to 20% are required by a developer before a non-utility generation project will be undertaken.

The rate of return offered by non-utility generation projects is closely linked to several other factors, as noted below.

Figure 8–4 **Energy Purchased from NUGs**





Energy resources like solar and wind may be developed by non-utility generators.

Purchase Rates and Avoided Cost

Purchase rates are the prices that Hydro pays for electrical capacity and energy from non-utility generators. The rate of return on investment, and thus the level of NUG development is directly linked to the purchase rate offered.

Hydro's policy allows for the total cost of the purchase to be equal to or less than the avoided cost to the system as a whole. This policy ensures that Hydro's customers will pay no more than if the power and energy purchased were produced by Hydro. The total cost of the purchase consists of the purchase rate, plus any financial assistance provided, plus any other contract terms that result in actual or potential costs to Hydro. The latter includes items such as the sharing of financial risk associated with potential increases in natural gas supply prices.

It is this total cost which must be evaluated against the system avoided costs. As explained in Chapter 6, the avoided cost is the cost that Hydro would incur in providing the same electrical supply as that of the non-utility generator.

For non-utility generation projects with capacities up to 5 MW, the purchase rates currently offered are somewhat higher than estimated avoided costs. These higher rates are designed to stimulate the initial development of small non-utility generation projects.

Non-utility generation projects with capacities greater than 5 MW are evaluated on a case-by-case basis. Evaluation of avoided cost considers factors such as reliability, the timing and location of deliveries, and the planned and committed supply requirements.

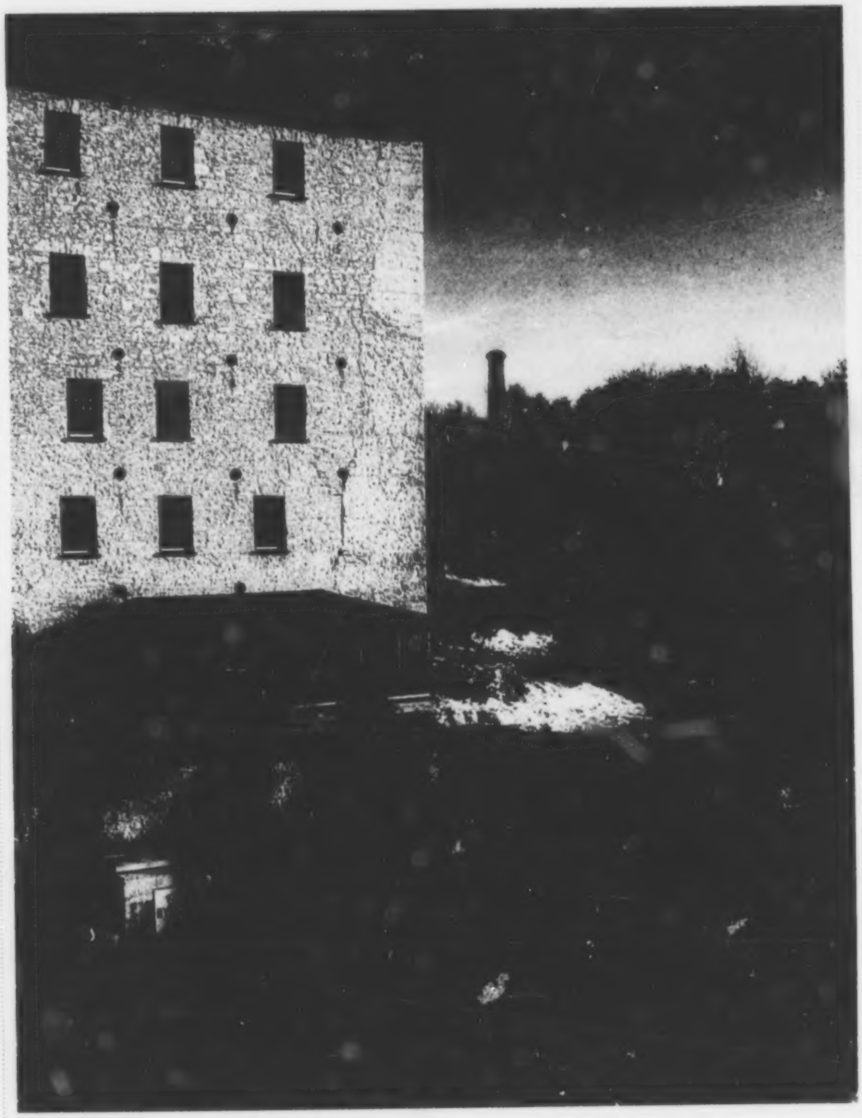
Favourable Tax Treatment

NUG development is also sensitive to tax treatment. The taxation system in Canada currently allows for an accelerated write-off of specific capital costs during the early years of a non-utility generation project (a Class 34 capital cost allowance). Hydro anticipates that most non-utility generators will meet the qualifications for such tax treatment.

Customer and Government Support

Non-utility generation is endorsed by the Ontario Government and by many of Hydro's commercial and industrial customers. Such support is evidenced in the Government's policy on parallel generation (another term for non-utility generation), released in July 1989, which states that "the Government will reduce barriers to the development of economically and environmentally sound parallel generation in the Province while protecting the interests of Ontario ratepayers."

The policy also recommends that Hydro's solicitation process be designed to achieve a "target of 1,000 MW of parallel generation[†] by 1995" and "provide the flexibility to achieve an additional 1,000 MW by the year 2000." Continued government and customer support is necessary to attain the levels expected in



Hydro expects that over 400 MW of hydraulic non-utility generation will be developed over the next 20 years.

the NUG Plan. Without this support, industry would be less interested in investing in non-utility generation projects.

The NUG Plan assumes that there will be no change in the regulatory framework which would have an adverse effect on the ability of NUG generators to obtain timely approvals.

Availability and Price of Natural Gas

The implementation of non-utility generation projects depends on the availability and price of fuel. Natural gas is particularly important as it is expected to fuel 70% of Ontario's NUG potential in the coming years. The assessment of NUG potential is based on the expectation that natural gas will continue to be readily available, and that non-utility generators will continue to be able to contract for it at an acceptable price.

Hydro's forecast of gas prices is presented in Chapter 15. Dedicated base load generation from gas is not economic, whether such generation is from NUGs or Ontario Hydro. However, these forecast prices are economic for peaking application. Also base load co-generation may be economic. If prices should rise above Hydro's gas price forecast, it will make gas-fueled co-generation less competitive.

POTENTIAL AND ATTAINABLE NUG

This section presents Hydro's forecast of non-utility generation expected to come into service over the 25-year planning period. The forecast begins with a review of the technical potential of projects fueled by natural gas, falling water and waste fuels that could be developed by non-utility generators. By factoring in equipment costs, fuel costs, interest rates, return on investment requirements and estimates of

Redpath Refineries has a generating capacity of 2.5 MW.

Hydro's purchase rates, this technical NUG potential is translated into a forecast of the potential that is economic from the NUG developer's perspective. The amount of NUG capacity that Hydro estimates will be constructed is then derived by factoring in considerations such as capital availability and individual choices of generation processes.

In developing the estimates of NUG potential, NUG projects are grouped according to their primary energy. Three categories of generation are considered and assessed separately:

- Natural Gas-Fueled;
- Falling Water; and
- Waste Fueled.

Natural Gas-Fueled Generation

The majority of new non-utility generators are expected to be fueled by natural gas. These will consist primarily of cogeneration facilities.

Cogeneration accounts for about 90% of the thermal or approximately 50% of all the non-utility generation capacity installed to date. The major fuel for these facilities is natural gas. Cogenerators are in a good position to produce electricity at a competitive cost, due to their fuel conversion efficiency.

Cogeneration potential is based on estimates of the actual demand for steam in the province. To estimate the technical electricity potential of cogeneration, it is assumed that existing conventional boilers are replaced by cogeneration facilities. Based on available studies, the technical potential is estimated to be 6,400 MW for the industrial sector and 6,200 MW for the institutional, commercial and residential sectors combined.

To refine this technical potential into an estimate of economic potential, the non-utility generation costs are compared with the revenue the project is capable of earning. Assuming that the customer will require a minimum internal rate of return of between 15% and 20%, and factoring in estimates of purchase rate, gas price and equipment costs, the economic potential of cogeneration is estimated.

For the industrial sector this amounts to 5,500 MW. Although the technical potential of the commercial and residential sectors is large, only a small percentage of it is economic. It has been estimated that about 30 MW of such cogeneration is economic.

Not all existing steam generation facilities will be replaced by cogeneration facilities at the same time. These projects will be developed as dictated by prevailing economics or the need for equipment replacement. When these considerations are taken into account, it is estimated that about 1,200 MW of the cogeneration potential could be attained by the year 2000. This is based on the assumption that 60% of the economic cogeneration capacity will be developed before the year 2000. For these projects, it is further assumed that initial development will amount to 35% of the total potential at each site.

Fifteen per cent of the remaining economic potential is expected to be developed by the year 2014. This will amount to approximately 50 MW per year between the years 2000 and 2014, for a total additional development of 750 MW.

Some of the cogeneration capacity will be used by the generator for load-displacement and some will be sold to Hydro as purchase generation. Based on currently identified projects, a split of 60% load-displacement and 40% purchase generation is forecast.

The technical potential of natural gas-fueled non-utility generation for electricity production only is estimated at 4000 MW. In the current NUG Plan, such generation is not seen as making a significant contribution, since natural gas is a relatively expensive fuel. This is particularly true of base load generation, where gas-fueling is likely to be more expensive than Hydro's avoided costs.

Nevertheless, natural gas-fueled generation has a role to play in the Demand/Supply Plan. Furthermore, Hydro's assessment indicates, that gas-fueled generation may be economic for peaking operations, and that future opportunities may therefore exist for natural gas-fueled NUG peaking plants.

Hydraulic Generation

Over the next 10 to 20 years, it is expected that most of the hydraulic non-utility generation projects in Ontario will have capacities of 10 MW or less. Sites with larger capacities are more likely to be developed by Hydro, as noted in Chapter 12.

The total known undeveloped hydraulic potential in Ontario amounts to about 12,400 MW. The amount available for non-

Figure 8-5 Summary of Potential and Attainable Non-Utility Generation Capacity (MW) [illegible] Plan

Conversion Process	Technical Potential	Economic Potential	Attainable by Year 2000	Attainable By Year 2014
Hydraulic	860	490	311	490
Cogeneration	12,600	5,530	1,178	1,900
Other Thermal	4,500	300	146	300
Total	17,960	6,320	1,635	2,690

utility generation however is reduced by a number of factors. These include:

- sites under consideration by Hydro for development;
- remote northern rivers which are environmentally sensitive;
- the prohibition on development in parks; and,
- high development costs.

All of the above factors reduce the total potential. Based on known projects, approximately 490 MW is expected to be economic and achievable over the next 25 years. Of this, approximately 311 MW could be attained by the year 2000. Achieving this level will require good coordination among Hydro, the Ministry of Natural Resources and private industry.

Waste-Fueled Generation

Waste-fueled generation facilities can burn fuels such as municipal solid waste (MSW), landfill gas or wood wastes to generate electricity. They are limited to those locations where there is sufficient availability of these fuels to sustain their development.

In Ontario, 20 centres have been identified as having sufficient population density to support projects producing energy from MSW and landfill gas. This amounts to 300 MW of technical potential. Assuming a success rate similar to that of natural gas-fueled cogeneration, about 100 MW of generating capacity is forecast to be attainable by the year 2000. This includes 35 MW which is already in service or committed. A growth rate of 6% per year is forecast after the year 2000.

The technical potential for wood waste-fueled generation is estimated to be 200 MW. Of this total, 50 MW is forecast to be attainable by the year 2000, with an annual growth rate of 6% thereafter.

A summary of the technical, economic, potential and attainable non-utility generation for Ontario is provided in Figure 8-5.

The attainable NUG capacity depends upon the avoided cost associated with the overall Proposed Demand/Supply Plan.

Illustrative avoided costs are presented in Chapter 16 of this report. The avoided costs associated with the Proposed Plan are lower than avoided cost evaluations in recent years because of two major factors:

- the expected future coal costs have been reduced; and
- the Proposed Plan is well defined and is

Natural gas is a major fuel source for cogeneration.

The paper industry is a significant non-utility generator.

lower cost than the plans assumed during the past few years.

The illustrative avoided costs in Chapter 16 are lower than avoided costs assumed in the development of the NUG potential. Accordingly, the attainable economic NUG capacity may be overestimated. This uncertainty of NUG yield is small compared with the load forecast uncertainty.

[illegible]

General Considerations

The smaller, localized and more dispersed nature of NUG projects across the province, suggests that their environmental and community impacts are generally less than those of conventional generation options which are larger, more centralized, and take longer to build. Thus, costs and benefits associated with NUG developments tend to be highly localized. Overall, there is a public preference for NUG projects and there is likely to be an increasing preference for them in the future.

Depending on location, the dispersed nature of NUG projects may pose problems of incorporation into Hydro's BES (bulk electricity system)†. The environmental effects associated with their incorporation may be significant if these sites are located some distance from existing lines.

A variety of NUG projects is likely to be undertaken in Ontario. The main categories include: gas-fueled cogeneration, municipal solid waste incineration, wood waste burning and small hydraulic generation.There are specific environmental concerns associated with each of the NUG categories. These are discussed below.

Gas-fueled Cogeneration

Most of the 2,690 MW of non-utility generation proposed to be developed over the next 25 years, is expected to be from natural gas-fueled cogeneration. These gas-fueled projects will produce some air emissions (i.e. NO_x, CO, CO_2) and have some measure of consumptive water use. Waste disposal concerns are expected to be minimal. There may be some potential effects associated with providing gas pipeline access to a site if a right-of-way does not already exist.

Co-generation projects can make industries more energy efficient and hence, more competitive. To the extent that this allows industries to prosper, there may be indirect employment and development benefits.

Municipal Solid Waste Incineration

Municipal solid waste (MSW) facilities offer an opportunity to both reduce local landfill requirements and produce electricity. Generally, however, MSW facilities have been strongly opposed in urban areas, as they are a perceived health risk by the public. The public has concerns that toxins (e.g. dioxins), resulting from the burning of plastics, can be released from MSW facilities. The delivery and stockpiling of garbage associated with the operation of a MSW facility also causes concerns about traffic, noise, and odour in the communities surrounding the plant.

The problem of toxic emissions can be effectively managed with appropriate emission control equipment. However, toxic materials removed from flue gas generally end up in the ash produced by the incinerator. The toxic nature of these wastes requires careful landfill practices to ensure that leachate is controlled.

Since new MSW facilities will likely be sited close to large urban areas, environmental control requirements are expected to be very stringent and expensive. Prudent processing of wastes, as well as proper buffering from surrounding communities, will also be important at these facilities.

Small Hydraulic Generation

Small hydraulic developments are defined as projects that generate less than 10 MW. They are usually developed on rivers that have existing control structures or dams that are not currently used for power generation. Many of these structures were originally installed for flood control purposes. Some dams were previously used for other industrial purposes such as grist milling. In other cases, new dams may be constructed at sites on smaller waterways, close to local industries requiring electricity. From the viewpoint of sustainable development, small-scale hydraulic development is a good option as it makes use of an indigenous, renewable resource. Public support for further hydraulic development is also high.

Redevelopment of existing control structures and dam sites is expected to have little adverse environmental effects. There may be, however, some short-term, localized effects on flows and sedimentation patterns in the affected waterway as a result of repairing structures, installing equipment or dredging headponds. Planning these construction activities to occur in periods of low river use reduces potential negative impacts.

Development of a new dam on a waterway can have significant effects on resident fish populations by disrupting spawning and migratory patterns, as well as other existing water uses such as boating. Construction of the dam can also have some temporary, localized effects on flows and turbidity, but careful construction planning should minimize long-term impacts. In particular, blasting must be timed to avoid biologically sensitive periods such as spawning seasons.

The NUG plan recognizes the opportunity for small hydraulic development.

As most small hydro facilities tend to be operated as run-of-the-river (non-peaking) plants, there is only limited reservoir storage and water level fluctuations are minimal. Generally, therefore, there is little impact on upstream or downstream flow patterns.

Wood Waste Burning Plants

As wood waste burning plants are generally developed in conjunction with existing pulp and paper operations, facilities are usually located in Northern Ontario where most forestry activity occurs. Facility development generally can be accommodated on existing kiln sites.

Wood burning produces atmospheric emissions (CO, CO_2, NO_x, and particulates) as well as ash residue that requires disposal. Appropriate stack emission controls and waste management practices can manage these environmental problems.

Construction of a wood waste generation facility in a northern community with high unemployment may provide a significant local stimulus for economic developement. There is also potential for host industries to become more competitive if energy savings are realized with these facilities.

	Purchase		Load Displacement		Annual Net Growth	Net Accumulated Growth
Year	Additions	Retirements	Additions	Retirements		
1989	28	0	62	17	73	73
1990	27	0	98	17	108	181
1991	171	0	83	17	237	418
1992	86	0	96	17	165	583
1993	86	0	96	17	165	748
1994	73	0	50	17	106	854
1995	73	0	51	17	107	961
1996	72	0	39	17	94	1055
1997	75	0	36	17	94	1149
1998	80	0	31	17	94	1243
1999	86	0	25	17	94	1337
2000	75	0	36	17	94	1431
2001–04	194	0	96	68	222	1653
2005–09	237	3	120	85	269	1922
2010–2014	235	73	120	85	197	2119

Ontario Hydro is committed to promoting and developing the maximum achievable level of economic non-utility generation. The NUG Plan outlined here is ambitious and Hydro is undertaking a variety of activities to ensure the Plan is realized. The levels set by the Plan represent both committed, site-specific projects and a general forecast of attainable non-utility generation based on Hydro's estimates of economic NUG potential.

Eleven committed NUG projects totalling 172 MW were under construction at the beginning of 1989. This includes the 90 MW cogeneration project at Fort Frances, a three-party agreement between Boise-Cascade, Inter-City Gas Utilities and Ontario Hydro. Developers of another 23 facilities totalling 216 MW have indicated to Hydro that they are committed to construction of their projects.

Apart from these committed projects, the NUG Plan provides an aggregate forecast of NUG additions over the next 25 years. In developing this forecast, Hydro has used the estimates presented earlier in this chapter for attainable NUG. The total capacity of non-utility additions is forecast to be 1,635 MW by the year 2000, and 2,690 MW by the year 2014.

As with Hydro's own system, the inevitable retirement of NUG facilities reduces generating capacity unless facilities are replaced. In order to determine the net capability of NUG for meeting future electricity needs, NUG retirements must be subtracted from new additions to generation.

As indicated in Figure 8–6, there is expected to be 1,431 MW of net growth in NUG capacity by the year 2000 after allowing for facility retirements. By the year 2014, the forecast net growth in NUG capacity is 2,119 MW after allowing for retirements.

The forecast comprises two components, purchase generation and load-displacement, which are shown separately in Figure 8–6.

Purchase generation is a supply option used to meet the primary load. The forecast net additions to purchase generation are 932 MW by the year 2000 and 1,522 MW by the year 2014.

Load displacement generation is similar to demand management and represents a reduction to the basic load forecast.

Figure 8–7 shows that the net additions forecast for load-displacement NUG projects is further divided into two categories: induced and natural. "Induced" load-displacement NUG refers to those projects that are a direct consequence of Hydro's NUG programs. "Natural" load-displacement NUG refers to those projects that would have developed in the absence of any action by Hydro.

Figure 8-7 NUG Load Displacement and Demand Displacement (Natural and Induced) MW

	Annual Net Load Displacement			Annual Net Dependable		Annual Net Demand Displacement		Cumulative Net Induced Demand Displacement
Year	Additions	Induced	Natural	Induced	Natural	Induced	Natural	
1989	45	61	−16	55	−14	59	−15	59
1990	81	46	35	41	32	43	33	102
1991	66	78	−12	70	−11	74	−11	176
1992	79	71	8	64	7	67	8	243
1993	79	71	8	64	7	67	8	310
1994	33	25	8	23	7	24	8	334
1995	34	26	8	23	7	25	8	359
1996	22	15	7	14	6	14	7	373
1997	19	12	7	11	6	11	7	384
1998	14	7	7	6	6	7	7	391
1999	8	1	7	1	6	1	7	392
2000	19	12	7	11	7	11	7	403
2001–04	28	16	12	14	10	15	11	418
2005–09	35	20	15	18	14	19	14	437
2010–14	35	20	15	18	14	19	14	456

Naturally occurring non-utility generation is forecast by extrapolating historical values. The difference between this extrapolated value and the forecast of total load-displacement generation represents the generation induced by Hydro's programs. Because of the incentive-driven nature of virtually all purchase generation NUG projects, purchase NUG projects are not categorized in this fashion.

Naturally occurring load-displacement generation is accounted for in the basic load forecast, while both natural and induced load-displacement generation are included in the computation of the primary load forecast, as described in Chapter 9.

As is also indicated in Figure 8–7, Hydro's planning must take account of two other factors: dependable capacity and demand displacement. Factoring in dependability reduces the total forecast of load-displacement NUG capacity available to account for effects such as outages and low river flows. The dependable capacity for all load-displacement non-utility generation is considered to be about 90% of installed capacity.

Similar to demand management options, load-displacement NUG facilities generally reduce Ontario Hydro's transmission line losses. To credit load-displacement generators for this benefit, a 5% allowance is made for line losses in determining the demand displacement of Ontario Hydro generation. The resulting net demand displacement values are shown in Figure 8–7.

Figure 8–8 shows the forecast net capacity additions from the NUG Plan for purchase generation (in terms of new capacity additions net of retirements) and for load-displacement generation (in terms of induced demand displacement net of retirements and transmission line losses).

As far as energy is concerned, new non-utility generators are expected to have high capacity factors. As a group, an average annual capacity factor of 80% is expected. This is largely a result of the energy-based purchase rates currently offered. Under these rates, non-utility generators earn their highest rate of return on investment when they operate at high capacity factors.

The forecast electricity production from non-utility generation additions is shown in Figure 8–9.

Upper and Lower Load Forecasts

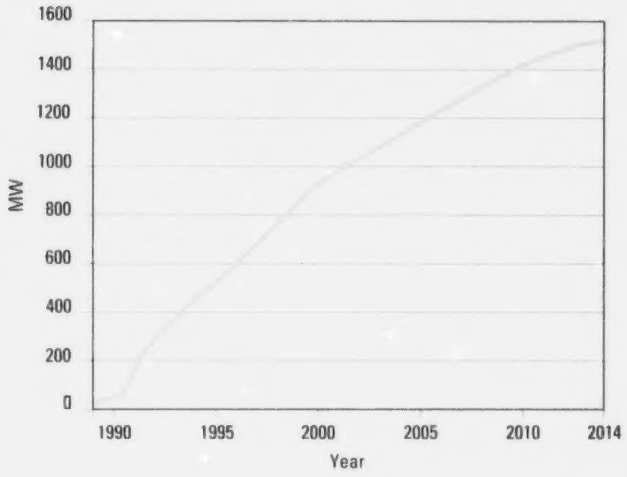
The Plan forecasts make one other major assumption: that the electricity system will develop according to the projections contained in the median load forecast. Changes in load growth will affect the NUG forecast through associated changes in the economy and changes in avoided costs. The latter will in turn have an impact on purchase rates. As the load growth forecast increases or decreases, so does the forecast of non-utility generation additions.

In this manner, non-utility generation adds flexibility in responding to load changes.

Anticipation of non-utility generation additions corresponding to the upper- and lower-bound load forecasts is required for planning purposes. These have been derived from the median forecast of the NUG Plan and are shown in Figure 8–10.

Regardless of actual load growth Hydro's basic aim would remain the same: to continue to promote the maximum attainable economic non-utility generation through purchase rates set at levels up to avoided costs.

Figure 8–8 **NUG Plan Capacity** Net Purchase NUG



A variety of activities must be undertaken to realize the NUG Plan. In addition to the promotion, development and administration responsibilities of Hydro's NUG Division, non-utility generation projects require the involvement of a number of Hydro divisions with various responsibilities: scheduling of power generation facilities; long-term planning of the electricity system; transmission interconnection requirements; equipment design and safety; and metering of capacity and energy purchases.

But efforts by Ontario Hydro alone will not be enough. Pursuing the maximum economic NUG potential will require a sustained and coordinated effort on the part of all parties involved: manufacturers, developers, fuel suppliers, consultants, financiers, government, municipal utilities and large steam users.

As is the case for encouraging demand management, Hydro's role is to make the organizational and procedural changes that will

Figure 8–8 **NUG Plan Capacity** Net Induced Demand Displacement

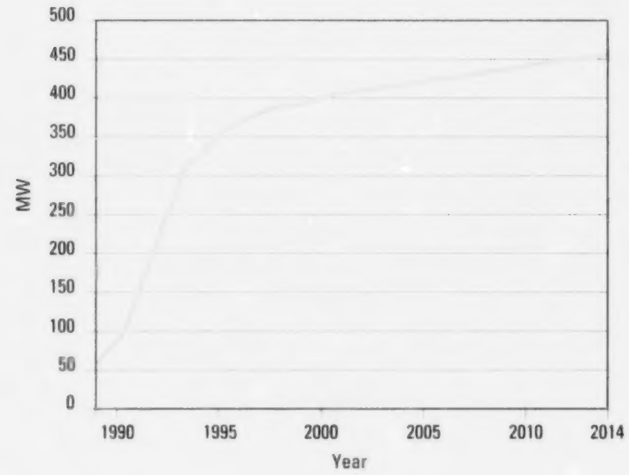


Figure 8–9 **NUG Median Energy Forecast**

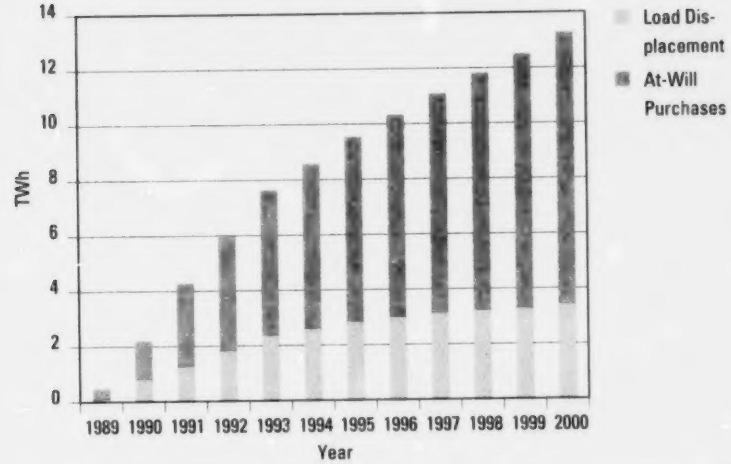
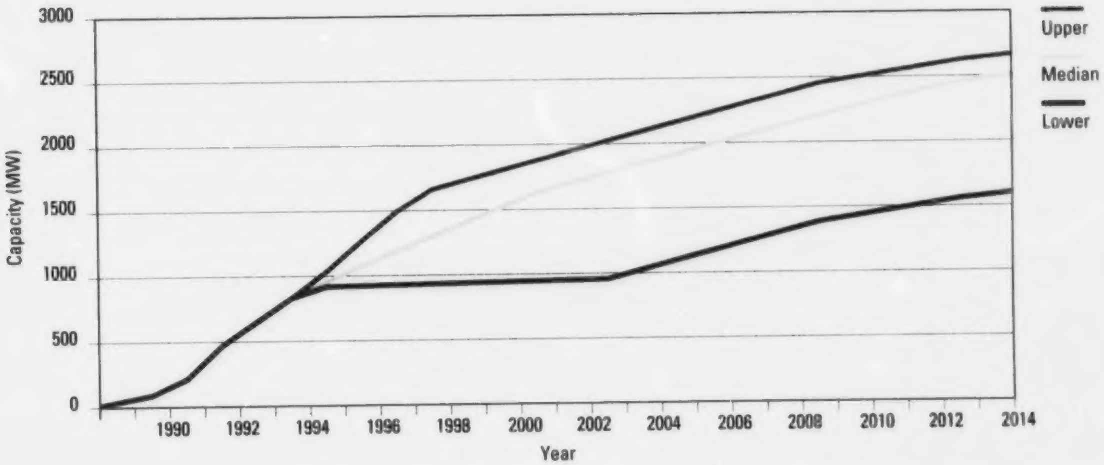
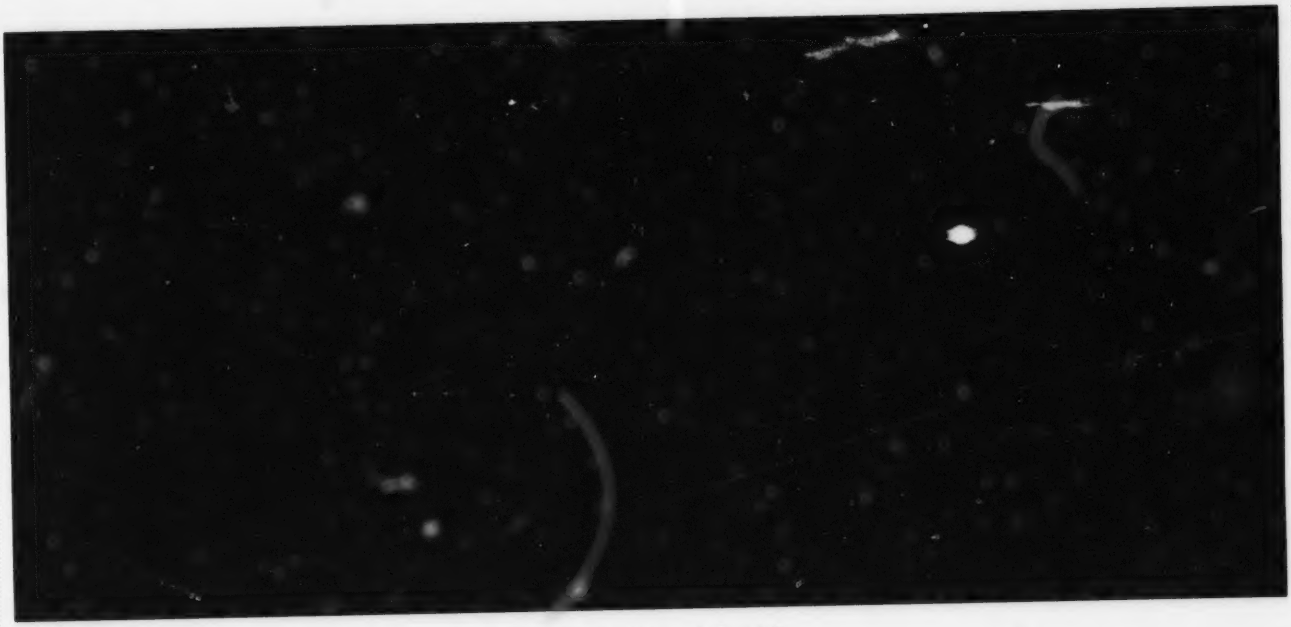


Figure 8–10 **Non-Utility Generation Forecast** Upper and Lower Load Paths



[illegible]

Region	**Company**	**Generation Process**	**Generating Capacity (KW)**
Central	Tricil Ltd.	Thermal/MSW	4231
Eastern	Fleming Feeds	Hydro	50
Eastern	Casselman Small Hydro	Hydro	375
Eastern	Galetta Power Ltd (Multistream)	Hydro	800
Eastern	Marsh Hydro Power (Trent Valley) Inc.	Hydro	1200
Eastern	Multistream Power Corporation	Hydro	325
Eastern	Nelson Fraser	Hydro	50
Eastern	Rideau Falls Generating Partnership	Hydro	2000
Georgian Bay	Williamsford Feed	Hydro	40
Georgian Bay	Burk's Falls Waterpower Corporation	Hydro	1000
Georgian Bay	Von Teichman	Hydro	135
Georgian Bay	Wilson Mill	Hydro	70
Northeastern	Black River	Hydro	490
Northeastern	Chapleau Cogeneration Ltd.	Cogen/Wood-Waste	7000
Northeastern	Marsh Hydro Power Inc.	Hydro	600
Northeastern	Scarfe Lake Electric Company Ltd.	Hydro	2000
Northwestern	Dorian Fish Hatchery	Hydro	16
Northwestern	Sundridge Power Corporation	Hydro	2880
Northwestern	Sundridge Power Corporation	Hydro	1000
Western	Grand River Conservation Authority	Hydro	150
Western	Grand River Conservation Authority	Hydro	690
Western	Pittens Farms Ltd.	Thermal/Biomass	40
Western	Richard and Brenda Kuiper	Hydro	110
Western	Upper Thames River Conservation Authority	Hydro	400
Total			25652



The heating system in the hospital serving this community cogenerates steam and electricity.

facilitate the development of economic non-utility generation. Many of these changes have already been made or are underway.

Solicitation for Capacity

Hydro is implementing a solicitation process for non-utility generation capacity. Under this arrangement, Hydro will issue periodic requests for proposals (RFP) to solicit projects with capacities above 5 MW. The underlying philosophy is to ensure non-utility generators fair and consistent treatment.

Numerous utilities in the United States and more recently in Canada have adopted competitive bidding for non-utility generation. In order to give the non-utility generation industry more time to gain experience in determining the costs of doing business, Hydro has introduced an open solicitation process rather than a competitive bidding process. With this process, there will be no direct competition among projects.

In the open solicitation, projects submitted must satisfy certain requirements before being considered. The requirements ensure that each project considered will benefit customers, generators and Ontario's electricity system. Project criteria are based in part on the technical requirements of the high voltage delivery system. They also include consideration of the degree of project proposal development and financial viability, to ensure that the proposed project will operate reliably throughout the contract period.

As the non-utility generation industry matures, various aspects of the competitive bidding process will be incorporated into the periodic solicitations. Once the bidding process has become fully competitive, Hydro will regularly issue an RFP for a specified block of capacity. In response, potential non-utility generators will submit proposals to supply some portion of this capacity. These proposals will be ranked according to a set of selection criteria encompassing both financial viability and technical considerations.

Prospective generators will then have the opportunity to negotiate and enter into firm contracts with Hydro. This competitive bidding process will be similar to those implemented successfully by other utilities.

Financial Assistance

In order to provide further encouragement to the industry, Hydro plans to allocate about $40 million annually for financial assistance, most of which will be applied as low-interest loans. The assistance is a way of providing higher rates of return to the customer or developer in the short-term. Over the long-term the cost of the assistance is recovered through a lower contracted purchase price. In all cases, the cost of any loan plus the purchase cost must be within the avoided cost.

Hydro will also contribute to the cost of consultant studies to determine the technical and financial feasibility of an eligible project. As well, Hydro will provide joint funding of some technology development and demonstration projects.

Other Activities

In addition to the above, Hydro has undertaken a number of other programs and activities. As noted earlier, Hydro has over the past two years conducted annual workshops for prospective non-utility generators. The purpose of these sessions has been to promote non-utility generation in Ontario and to openly discuss current NUG issues with non-utility generation industry representatives. The workshops have been well attended and received by the industry.

Hydro also participates in several committees concerned with non-utility generation development. One such committee is the Non-Utility Generation Advisory Council (NUGAC), chaired by the Ministry of Energy. NUGAC provides a forum for dialogue among Hydro, industry and government on the subject of developing non-utility generation in Ontario.

[illegible]

Region	Company	Generation Process	Generating Capacity (KW)
Central	Kodak Canada Inc. Ltd.	Cogen	1000
Central	Redpath Sugar	Cogen	2500
Central	St. Lawrence Starch Company Ltd.	Cogen	3250
Central	Stelco	Cogen	10000
Eastern	Almonte PUC	Hydro	840
Eastern	Alvin Beeler	Hydro	20
Eastern	Bancroft	Hydro	260
Eastern	Campbellford	Hydro	2075
Eastern	Canadian General Electric	Cogen	2000
Eastern	E.B. Eddy Forest Products Ltd.	Hydro	9300
Eastern	Eganville	Hydro	400
Eastern	Gananoque L&P	Hydro	6130
Eastern	Gananoque L&P	Thermal/Diesel	5770
Eastern	Ottawa Hydro	Hydro	12306
Eastern	Pembroke HEPC	Thermal/Diesel	1610
Eastern	Peterborough PUC	Hydro	4100
Eastern	Renfrew	Hydro	1980
Eastern	Trent University	Hydro	2220
Eastern	University of Ottawa	Cogen	1300
Georgian Bay	Bracebridge Hydro	Hydro	2000
Georgian Bay	Orillia Water L&P	Hydro	14512
Georgian Bay	Orillia Water L&P	Thermal/Diesel	2136
Georgian Bay	Parry Sound PUC	Hydro	1340
Northeastern	Abitibi Price	Hydro	97895
Northeastern	Algoma Steel Corporation	Cogen	26250
Northeastern	Boise Cascade Canada Ltd.	Cogen	3750
Northeastern	Denison Mines Ltd.	Cogen	1600
Northeastern	E.B. Eddy Forest Products Ltd.	Hydro	13870
Northeastern	E.B. Eddy Forest Products Ltd.	Cogen	2500
Northeastern	Frontier Lodge	Hydro	80
Northeastern	Great Lakes Power	Hydro	235575
Northeastern	INCO Metals Company	Hydro	46890

[illegible]

Region	Company	Generation Process	Generating Capacity (KW)
Northeastern	INCO Metals Company	Cogen	18750
Northeastern	Kinsmen Park	Hydro	200
Northeastern	MacMillan Bloedel	Cogen	10000
Northeastern	MacMillan Bloedel	Hydro	9350
Northeastern	Malette Kraft	Cogen	15000
Northeastern	Malette Kraft: Smooth Rock	Hydro	6250
Northeastern	Rio Algom	Cogen	1500
Northeastern	Spruce Falls Pulp & Power Co. Ltd.	Hydro	54600
Northeastern	Spruce Falls Pulp & Power Co. Ltd.	Cogen	21600
Northeastern	Weldwood of Canada Ltd.	Cogen	750
Northwestern	Boise Cascade (Fort Francis)	Hydro	29800
Northwestern	Boise Cascade (Kenora)	Hydro	28000
Northwestern	Cdn Pacific Forest Product, Dryden	Cogen	6666
Northwestern	Cdn Pacific Forest Product, Thunder Bay	Cogen	80570
Northwestern	James River Marathon	Cogen	15500
Northwestern	Ministry of Government Resources	Hydro	20
Western	Brantford Water Treatment Plant	Hydro	140
Western	Canadian Niagara Power	Hydro	94675
Western	Canadian Industries Ltd.	Cogen	25000
Western	Dow Chemical	Cogen	238650
Western	Elora Mill	Hydro	110
Western	Gary Folkema	Hydro	15
Western	General Chemical Canada Ltd.	Cogen	10950
Western	Hiram Walker	Cogen	7500
Western	James Wilson & Sons Ltd.	Hydro	80
Western	Polysar Ltd.	Cogen	51031
Western	St. Jacob's Country Mill	Hydro	90
Western	St. Lawrence Seaway Authority	Hydro	12000
Western	Tage Hansen	Cogen	400
Western	University of Western Ontario	Cogen	1300
Western	Victoria Hospital	Thermal/MSW	6250
Total			1262196

Further beneficial programs, which address the specific needs of the industry, will be developed and implemented as necessary. These include programs such as financial assistance and remote community development. Hydro will also continue to issue information and promotional material to inform stakeholders both within and outside of the Corporation.

It is Ontario Hydro's stated objective to maximize the utilization of economic non-utility generation. Based on an assessment of current projects and the existing potential for new generation, it is estimated that approximately 1,600 MW of additional non-utility generation capacity can be attained by the year 2000. Achieving this will not be an easy task. While Hydro has undertaken a number of activities, a sustained and coordinated effort on the part of private industry, customers, financiers, government, other utilities will also be required.

The achievement of the forecast level is also highly dependent on external factors such as natural gas prices, industry steam requirements and tax treatment. The flexibility built into the Demand Supply Plan will help Ontario Hydro mitigate the uncertainties surrounding such issues.

The NUG Plan for 2014 is as follows:

- Purchase NUGS (net): 1522 MW
- Demand Displacement (net induced): 456MW.

9 THE PRIMARY AND FIRM LOAD FORECASTS

Chapter 3 discusses the Basic Load Forecast which is the customer electricity demand (power and energy) in the absence of certain Ontario Hydro programs designed to influence that demand.

Chapters 7 and 8 describe the plans for reduction in demand through Electrical Efficiency Improvements (EEI), Load Shifting (LS) and Load Displacement – Non-Utility Generation (LD-NUG).

This chapter discusses the resulting lower level of demand forecast which is called the Primary Load Forecast. The Primary Load Forecast is the forecast of power and energy which Ontario Hydro would normally generate or purchase in order to meet customer demands. The Primary Load Forecast is produced annually and takes account of the impacts of past Hydro demand management and non-utility generation programs and projections of their future impacts. Capacity Interruptible Loads (CIL), discussed in Chapter 7, further reduce the peak demand when required. When the Capacity Interruptible Loads are subtracted from the Primary Load Forecast, the result is the Firm Load Forecast. The Firm Load Forecast is used to determine supply requirements.

In Chapter 3, the Basic Load Forecast is presented as a bandwidth to reflect the uncertainty in future demand. In Chapter 7, the plans for Electrical Efficiency Improvements (EEI), Load Shifting (LS), and Capacity Interruptible Loads (CIL) vary with the upper, median and lower growth forecasts. Thus, the median Primary Load Forecast is the median Basic Load Forecast less the plans, corresponding to the median growth, for Electrical Efficiency Improvements (EEI), Load Shifting (LS), and Load Displacement – Non-Utility Generation (LD-NUG).

The upper and lower Primary Load Forecasts are derived in a similar manner.

The median Firm Load Forecast is the median Primary Load Forecast less the corresponding Capacity Interruptible Loads. Similarly the upper and lower Firm Load Forecasts are the upper and lower Primary Load Forecasts less the corresponding plans for Capacity Interruptible Loads.

The Primary Load Forecast

The median Primary Load Forecast for peak power and energy is illustrated in Figures 9–1 and 9–2. These two figures show the reduction in the Basic Load Forecast resulting from the Electrical Efficiency Improvements (EEI) plan, the Load Shifting (LS) plan and Load Displacement – Non-Utility Generation (LD-NUG) plan.

The Primary Load Forecast used in this document is based on the Basic Load Forecast issued in December, 1988, and the demand management and non-utility generation plans developed by September, 1989. The upper,

Figure 9–1 **Primary and Firm Load Forecasts – Peak Power Demand**

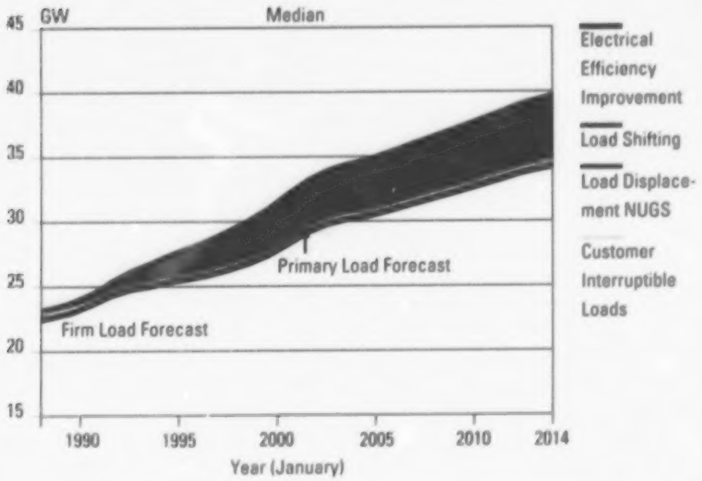


Figure 9–2 **Primary And Firm Load Forcasts – Annual Energy Demand**

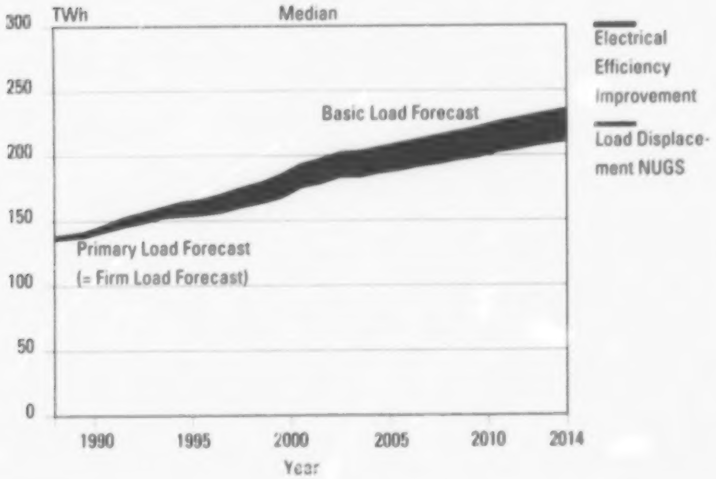


Figure 9–3 **Primary Load Forecast – January Peak Power Demand (GW)**

Year	Lower	Median	Upper
1989	22.7	23.2*	24.0
1990	22.3	23.7	24.8
1991	22.5	24.2	25.7
1992	22.7	24.9	26.8
1993	22.8	25.5	27.9
1994	22.8	25.8	28.5
1995	22.8	26.2	29.3
1996	22.8	26.5	29.9
1997	22.6	26.7	30.3
1998	22.8	27.1	30.9
1999	22.9	27.5	31.5
2000	23.2	28.1	32.3
2001	23.9	28.9	33.2
2002	24.9	29.8	34.3
2003	25.3	30.4	35.1
2004	25.8	30.8	35.5
2005	25.6	31.0	35.8
2006	25.8	31.3	36.2
2007	26.3	31.8	36.5
2008	26.8	32.2	36.8
2009	27.2	32.6	37.1
2010	27.7	33.0	37.4
2011	28.3	33.4	37.6
2012	28.7	33.9	38.0
2013	29.2	34.3	38.3
2014	29.7	34.8	38.6

**January 1989 Actual Primary Load was 23.1 GW*

Figure 9–4 **Primary Load Forecast Annual Energy Demand (TWh)**

Year	Lower	Median	Upper
1989	131	137	141
1990	132	139	146
1991	133	143	152
1992	135	149	159
1993	135	152	165
1994	135	155	171
1995	136	158	174
1996	135	158	177
1997	136	161	182
1998	138	164	186
1999	140	167	191
2000	142	171	196
2001	148	179	204
2002	152	182	210
2003	154	186	213
2004	155	187	215
2005	156	189	217
2006	158	192	220
2007	161	194	221
2008	165	197	224
2009	167	199	225
2010	171	202	227
2011	174	205	229
2012	176	208	231
2013	179	210	232
2014	182	214	235

median and lower primary load forecasts are tabulated in Figure 9–3 for peak power demand and in Figure 9–4 for energy demand.

For the year 2000, the demand reduction plans result in 7.1% energy reduction and 9.8% peak power reduction relative to the Basic Load Forecast. The impact on peak power is expected to be greater than the impact on energy because time-of-use rates only affect peak power. Figure 9–5, shown below, illustrates this.

Over the 1988–2000 period, the median Basic Load Forecast for peak power increases by 8.1 GW. The demand reduction plans for the same period are 3.0 GW (EEI of 1.7 GW, LS of .946 GW, and dependable LD-NUGs of .388 GW by January 2000). This means the demand reduction plans meet 37% of the

Figure 9–5 **Daily Load Shifting – Power**

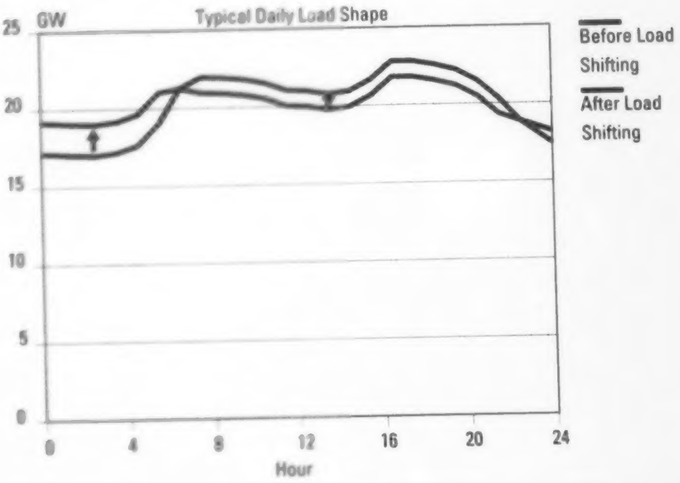


Figure 9–6 Average Year-Over-Year Growth Rates

	Median Load Forecast				
		Peak		Energy	
Period	Firm	Primary	Basic	Primary	Basic
1988–1995	2.3%	2.1%	2.8%	2.3%	2.8%
1988–2000	1.9%	1.8%	2.7%	2.0%	2.7%
1988–2010	1.8%	1.7%	2.3%	1.9%	2.3%
1988–2014	1.6%	1.6%	2.1%	1.8%	2.2%

Figure 9–7 Demand Levels (January figures)

	Median Load Forecast				
		Peak (GW)		Energy (TWh)	
Period	Firm	Primary	Basic	Primary	Basic
1988 Actual	21.9	22.6	22.6	134.4	134.4
1990	22.9	23.7	23.8	139	140
1995	25.6	26.2	27.5	158	163
2000	27.4	28.1	31.1	171	184
2005	30.3	31.0	34.9	189	205
2010	32.3	33.0	37.5	202	220
2014	34.0	34.8	39.8	214	234

median Basic Load Forecast *increase*. For the same 1988–2000 period, the median Basic Load Forecast for energy increases by 50 TWh. The demand reduction plans for this period reduce basic energy demand by 13 TWh, corresponding to 26% of the basic load forecast *increase*.

Firm Load Forecast

Figure 9–1 and Figure 9–2 also illustrate the Firm Load Forecast. It should be noted that the Capacity Interruptible Load reduction is for peak power only. The supply system is planned to have sufficient capacity to meet the Firm Peak Load reliably.

The Firm Peak Load Forecast is derived by subtracting the forecasted contribution of Capacity Interruptible Load from the Primary Peak Load Forecast. The Firm Energy Load Forecast is the same as the Primary Energy Load Forecast because the frequency and duration of load interruptions are relatively small and the customers' lost production may be made up at a later date. The Primary Load Forecast and the subtraction of the Capacity Interruptible Load gives the Firm Load Forecast. These forecasts are illustrated in Figure 9–1.

Figure 9-8 **Firm Load Forecast**
January Peak Power Demand

Year	Lower GW	Median GW	Upper GW
1989	22.0	22.4*	23.2
1990	21.6	22.9	24.0
1991	21.9	23.6	25.1
1992	22.1	24.3	26.1
1993	22.2	24.9	27.2
1994	22.2	25.2	27.9
1995	22.2	25.6	28.6
1996	22.3	25.9	29.2
1997	22.0	26.1	29.5
1998	22.2	26.4	30.1
1999	22.3	26.8	30.8
2000	22.7	27.4	31.5
2001	23.3	28.2	32.4
2002	24.3	29.1	33.5
2003	24.7	29.7	34.3
2004	25.1	30.1	34.7
2005	25.0	30.3	35.0
2006	25.2	30.6	35.3
2007	25.7	31.0	35.7
2008	26.2	31.4	36.0
2009	26.6	31.8	36.3
2010	27.1	32.3	36.5
2011	27.7	32.7	36.8
2012	28.1	33.1	37.1
2013	28.5	33.6	37.4
2014	29.0	34.0	37.7

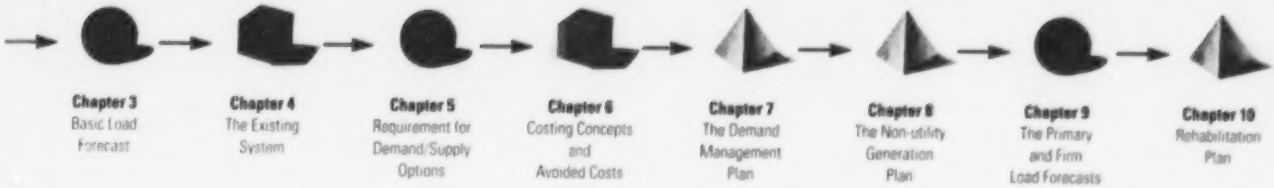
**January 1989 Actual Firm load was 22.4 GW*

Forecasted Growth Rates and Demand Levels

Figure 9-6 shows the growth rates for selected periods for the firm, primary and basic load forecasts. This tabulation shows how the demand reduction plans reduce the growth rate. For example, in the period from 1988–2000, the demand reduction plans reduce the Basic Load Forecast peak demand growth rate of 2.7% to the Primary Load Forecast growth rate of 1.8%. For energy, the corresponding reduction is from 2.7% to 2.0%.

Figure 9-7 shows the demand levels for the Firm, Primary and Basic Load Forecasts for energy and power (peak) for the 26-year period from 1988–2014.

The upper, median and lower Firm Load Forecasts are tabulated in Figure 9-8. ●


Chapter 3
Basic Load Forecast
Chapter 4
The Existing System
Chapter 5
Requirement for Demand/Supply Options
Chapter 6
Costing Concepts and Avoided Costs
Chapter 7
The Demand Management Plan
Chapter 8
The Non-utility Generation Plan
Chapter 9
The Primary and Firm Load Forecasts
Chapter 10
Rehabilitation Plan

Chapter 4 provided a brief description of Ontario Hydro's existing and committed generation facilities. Throughout the 25-year planning period, more of Ontario's primary load will be provided by these facilities than from new supply.

At the end of this period, existing generation facilities are expected to supply about two-thirds of the total primary energy demand for the median load forecast. Making the best use of existing stations is given a high priority in the Demand/Supply Planning Strategy.

As existing facilities operate and age, they will deteriorate. Furthermore their operation may have to conform with new regulations. These facilities may require rehabilitation involving major expenditures to ensure continuing safety, economy and environmental protection. Improving the performance of existing facilities can be more economic than building new facilities, and maximizes the benefit of existing assets.

This chapter has four objectives: define what is meant by rehabilitation; describe plans for ensuring good performance from Ontario Hydro's existing hydraulic, fossil and nuclear stations; describe the role of mothballed facilities in the bulk power system; and outline how redevelopment of hydraulic and fossil sites fits in with the Demand/Supply Plan.

Rehabilitation is a major restoration or improvement of a generating unit's long term performance which assures or extends the life expectancy. Over the course of the unit's life, it will receive maintenance and from time to time capital modifications may be undertaken. When large amounts of work are required throughout the station, a major rehabilitation may be needed. As illustrated in Figure 10–1, the boundaries between maintenance, capital modifications, and rehabilitation are not precisely defined.

Rehabilitation is carried out to:

- Rectify deteriorating performance in the long term;
- Ensure compliance with new environmental and safety requirements; and,
- Replace inefficient or technically and economically obsolete equipment.

Although rehabilitation requires major outages to carry out the necessary work, it does not include significant changes to the primary electricity production process.

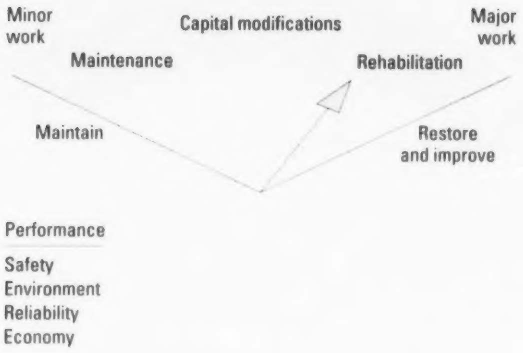
Performance of Generation Facilities

Some equipment in generating stations is designed to operate for the stations full service life. Other equipment, however, requires replacement during the station's service life.

The causes of deterioration in performance include:

- Aging;
- Operating time;

Figure 10–1 **Rehabilitation & Performance**



Type of Deterioration	Causes
Corrosion	Steam and water impurities, coal constituents which may result in acidic deposition
Cracking	Extended use and wear out
Creep†	High steam temperature, pressures or radiation
Fatigue	Stress induced vibrationally or thermally, periodic steam forces, electrical forces
Erosion	High velocity water and steam and particles such as coal and fly ash

- Operating patterns (eg. start-and-stop cycles); and,
- Stress (high operating temperature and pressure).

Equipment components deteriorate due to a number of phenomena which may depend on the electricity production process as outlined in Figure 10–2.

The Rehabilitation Plan is a set of major programs to restore performance that has severely deteriorated; to improve performance; or to meet new requirements.

Declining reliability of a station is an indicator of equipment deterioration. Figure 10–3 illustrates a typical trend for age-induced unavailability. During normal operation most equipment exhibits a basic pattern for reliability, commonly referred to as the "bathtub" curve.

Rehabilitation provides for potential gains in reliability as illustrated in Figure 10–3.

Improvements To Existing Facilities

During the operating life of a generating station, opportunities arise which lower costs through improving efficiency and increasing power output. Improvement may also be related to environmental or safety performance.

The following are examples of improvements being made to existing facilities:

- New flue gas conditioners are being installed to enhance the capture of fly ash particulates in the precipitators to permit the use of low sulphur coal. These conditioners are being installed on all units at Lambton, Nanticoke and Lakeview.

- The turbine-generators at Bruce A nuclear station have recently been modified to increase the station output by 400 MW. With this modification the turbines can use the excess steam previously intended for heavy water production.
- There has been ongoing work since the mid-1970s to increase output from existing hydraulic stations.

Many of the hydraulic generating stations built in the early 1900s are nearing the end of their expected 90 year service life, as illustrated in Figure 10–4. Almost all of the capacity is planned to be rehabilitated or redeveloped on an ongoing basis to make continuing use of this renewable energy source.

There are four hydraulic rehabilitation programs:

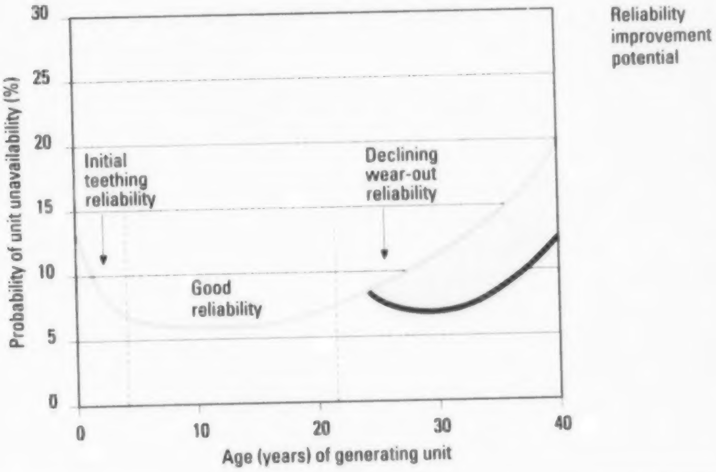
- Small Hydraulic Assessment & Retrofit Program
- Turbine Upgrade Program
- Process Control Improvement Program
- Dam Safety Assessment Program

Small Hydraulic Assessment & Retrofit Program

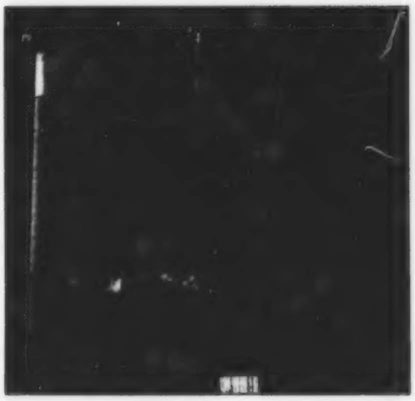
Thirty-seven of the 68 hydraulic stations have unit capacities of 10 MW or less. The Small Hydraulic Assessment & Retrofit Program (SHARP) was launched in 1988 to assess the condition and identify potential concerns associated with these facilities. The assessment will include technical and financial evaluation

The Rehabilitation Plan is a set of major programs to restore performance that has severly deteriorated; to improve performance; or to meet new requirements.

Figure 10–3 **Reliability Trend of Generating Unit**



Rehabilitation at Meyersberg Generating Station.



The Hearn Generating Station.

of all aspects of the generating facility: structure, equipment, water availability and potential energy production. Recommendations will be made to rehabilitate, redevelop or retire each facility. Implementation of the SHARP recommendations will span a 20-year period.

Turbine Upgrade Program

The Turbine Upgrade Program began in 1974, with the objective of identifying and upgrading sites which were underdeveloped (high flows relative to station discharge capabilities) or underutilized (poor turbine efficiency). Some 51 units have been upgraded, mostly through runner replacements or runner blade angle changes. As a result, average annual energy production has increased by over 300 GWh, and installed capacity by about 272 MW. Upgrades that could potentially yield additional capacity and energy are being studied on an ongoing basis.

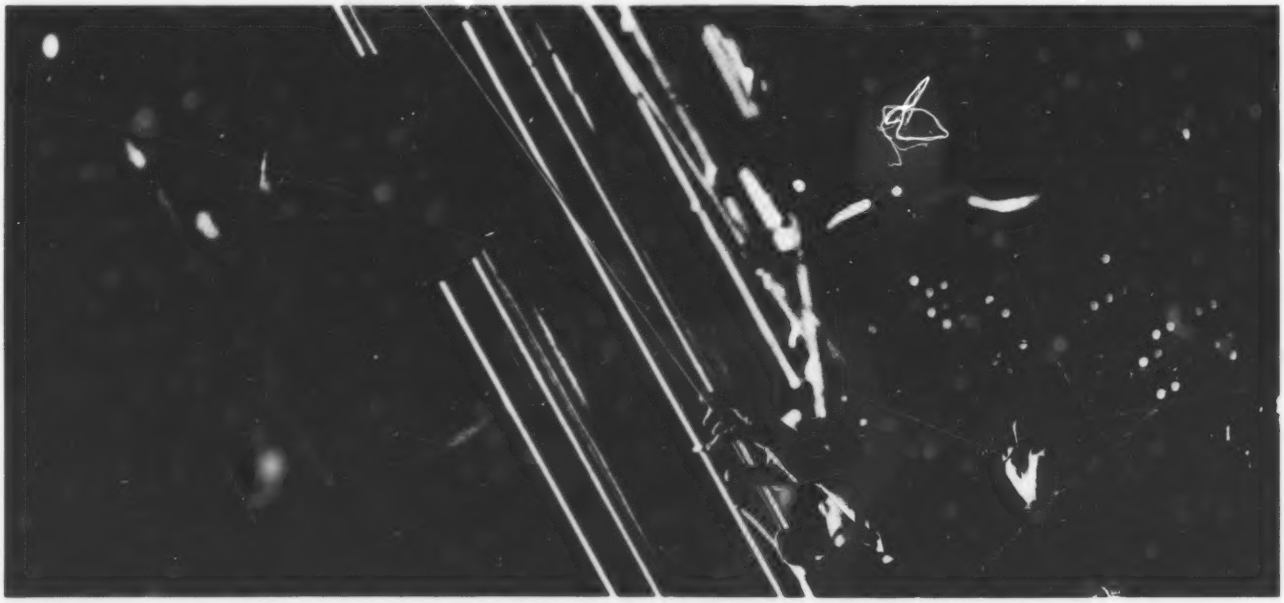
Process Control Improvement Program

The Process Control Improvement Program involves the installation of modern control and instrumentation equipment in hydraulic stations. The program is directed to:

- improve reliability;
- reduce operating costs; and,
- improve operating flexibility with more effective control equipment.

Dam Safety Assessment Program

A Dam Safety Assessment Program is also underway, to ensure the safe and reliable operation of Hydro's aging dams, reservoirs and hydraulic structures. Rehabilitation work will be initiated based on the findings of this program.

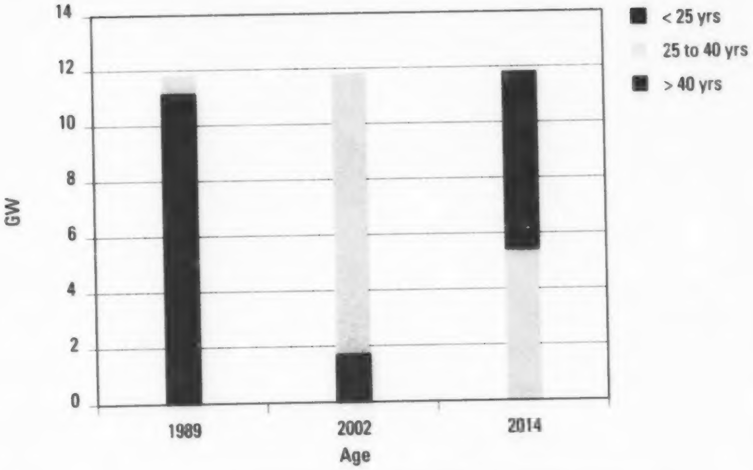


Monitoring emissions. Retrofitting scrubbers is a major component of the Rehabilitation Plan.

Figure 10-4 Age Of Existing Hydraulic Stations

	1989		2014	
Age (years)	**No. Of Units**	**Capacity (MW)**	**No. Of Units**	**Capacity (MW)**
0 to 25	18	1396	0	0
26 to 50	107	4048	18	1396
51 to 75	86	970	107	4048
76 or higher	54	78	140	1048

Figure 10–5 **Age of Existing Fossil Capacity**

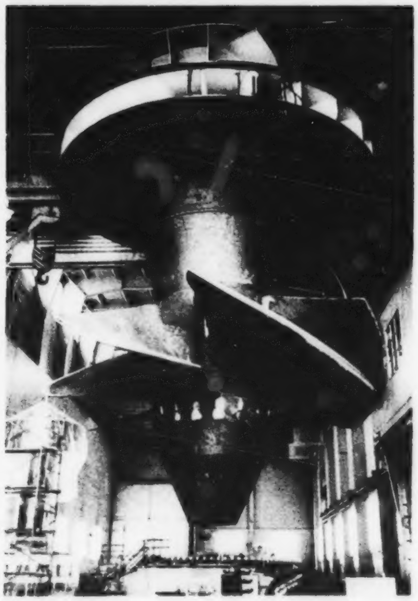


FOSSIL GENERATION REHABILITATION PLAN

A large part of Hydro's fossil generation is at or approaching the half-way point of an expected 40-year service life, as illustrated in Figure 10-5, and consequently is experiencing the effects of aging. Aging effects arise from a combination of its years in service, total number of operating hours and the number of times the unit has been started and stopped. These effects are a function of exposure to high temperatures and pressures, and the changes in these variables. Thermal cycles, where the temperatures and pressures are repeatedly changed, also have an impact on aging effects. Fossil generating units undergo many thermal cycles through startups and shutdowns because of the role of these units in supplying peaking and intermediate loads, and in meeting the generation shortfalls created when other generation is out of service. In addition, there are small, but more frequent, thermal cycles as the electrical output is raised and lowered to follow changes in demand during the day.

Experience has shown that deterioration in equipment and unit reliability becomes pronounced once a fossil unit has operated for about 100,000 hours and has experienced about 1,000 startup and shutdown cycles. Of the large fossil units in the bulk power system, the Lakeview and Lambton units have accumulated these levels of operating hours and startups.

The reliability of the fossil generating units has been deteriorating in recent years. The Lakeview units have been operating for the past 20 to 27 years and their reliability has decreased significantly in the recent past. To a lesser extent, the Lambton generating units have also decreased in reliability.



Turbine unit upgrades at hydraulic stations have resulted in increased energy output.

Acid Gas Reduction Plan

The Ontario Government's regulation to control Hydro's acid gas emissions requires Hydro to reduce its emissions in three stages as outlined in Chapter 4.

Hydro's approach to controlling its acid gas emissions over the long term is to develop various control options and put in place the most appropriate ones, as and when required. Control options can be divided into four broad categories: reduction of coal use, reduction of the sulphur content in fuel, development of clean-coal combustion technologies and installation of emission control technology. Each one of these options is being considered on an ongoing basis.

Hydro has committed capital expenditures to install flue gas conditioners at the Lambton, Nanticoke and Lakeview coal-fueled generating stations. The conditioners will provide the stations with the ability to burn lower sulphur coal to reduce acid gas emissions, and enhance the capture of fly ash particulates in the precipitators. This will assist Hydro in complying with the regulated emission limit in the early 1990s and beyond.

Modified burners were installed at Nanticoke, in the 1985 to 1987 period, to reduce nitrogen oxide (NO_x) emissions at the station by about 35%. Further combustion process modifications for NO_x control are being planned for Nanticoke and other stations.

The Ontario Government recently approved Ontario Hydro's Program Environmental Assessment for acid gas control, which facilitates installation of scrubbers at the larger fossil

As stations age, they require additional repairs and eventually rehabilitation.

stations. Installation of the first pair of scrubbers on two 500 MW units at Lambton by 1994 has been committed.

The type of acid gas controls and timing will depend on the various demand and supply options selected. Chapter 15 details the acid gas control facilities for the different plans.

Rehabilitation Plans For Fossil Stations

In the mid 1980s, Hydro initiated studies to assess the condition of fossil stations, owing to the decline in reliability of the generating units, and concern that the stations might have to be permanently retired. Premature shutdown of existing fossil generation facilities would add to the demand/supply requirements in the near term and decrease the generation capability of the existing system.

Lakeview Rehabilitation

In 1986, a study was initiated to assess the condition of Lakeview. Rehabilitating Lakeview was examined and compared with other options. Rehabilitating the station is economic, and will enable the eight units to operate, on average, until 2006 by which time they will have reached their expected 40-year service lives. In March 1989, the Ontario Hydro Board of Directors approved the rehabilitation work at Lakeview over the 1990 to 1994 period.

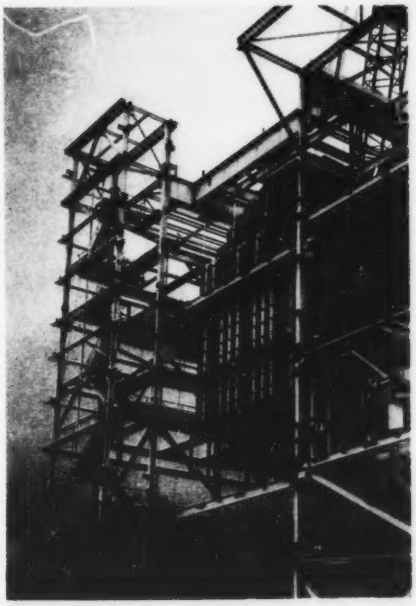
Lambton Rehabilitation

A study is underway to identify the condition of systems and components at Lambton. The study will identify rehabilitation work needed to reverse the trend of decreasing reliability. Depending on the scope of the rehabilitation needs, the work would likely be carried out over the 1992 to 1995 period in conjunction with the installation of scrubbers.

Other Fossil Stations

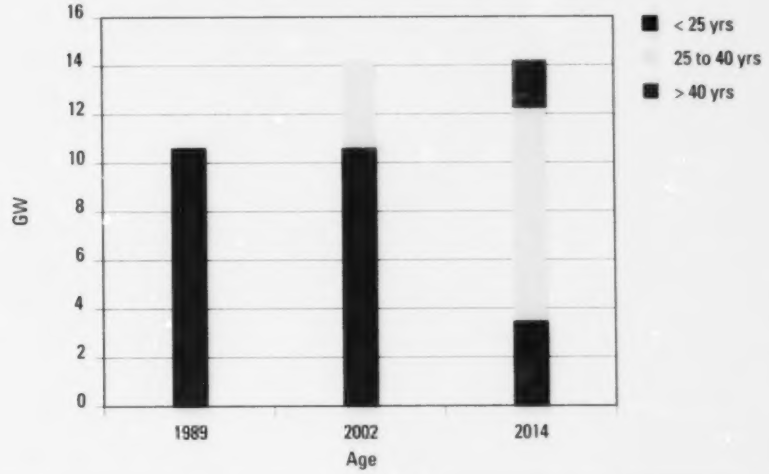
The Nanticoke units were placed in-service between 1972 and 1978. Alternative options to ensure the 40-year expected service life for this station are under consideration.

Lennox, Thunder Bay 2 & 3 and Atikokan stations were installed in the late 1970s or early 1980s. These stations are relatively new and specific rehabilitation plans are not required for some time.



Installing a scrubber is a major construction project.

Figure 10–6 **Age of Existing & Committed Nuclear Capacity**



Stack repair at the Lakeview Generating Station.

Nuclear generating units are younger on average than hydraulic or fossil generating units, as illustrated in Figure 10–6.

CANDU units are less prone to physical deterioration than fossil units because they are base loaded (less thermal cycling) and operate at much lower temperatures and pressures. However, some reactor components do operate in a radiation environment which causes deterioration.

The availability of the older nuclear generating units has declined in recent years. The main contributing factor is the need for fuel channel retubing.

There are two main rehabilitation programs underway for the nuclear stations:

- Fuel Channel Rehabilitation; and,
- Nuclear Plant Life Assurance program.

Fuel Channel Rehabilitation

A comprehensive fuel channel rehabilitation program has been in place since 1984. There are three main categories of fuel channel rehabilitation:

- Repositioning End Fittings and Bearings (REFAB)

As a result of radiation in the reactor fuel channel the pressure tubes grow in length. The REFAB program resupports pressure tubes onto their end fittings and bearings.

- Large Scale Fuel Channel Replacement (LSFCR)

Pressure tubes are not designed for the full service life of the nuclear stations. In light of metallurgical deterioration with age, reactors will require replacement of all or a major fraction of their pressure tubes during their expected 40-year life time.

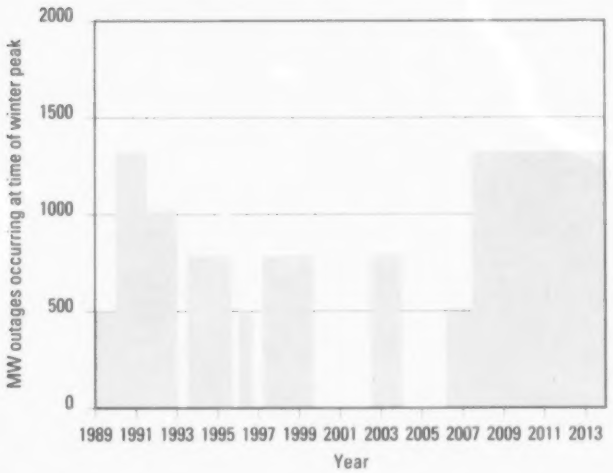
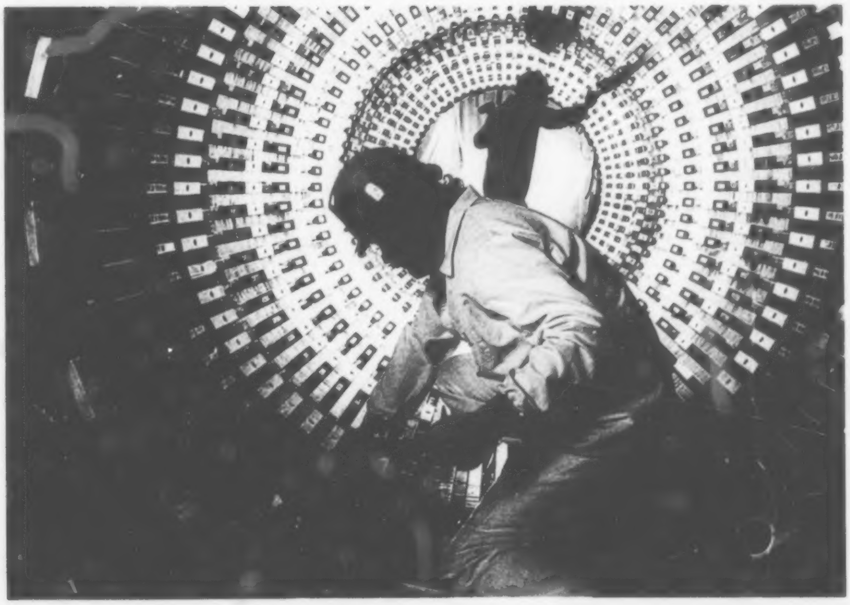


Figure 10–7 **Fuel Channel Rehabilitations (Nuclear Units)**


Workers repairing a generator at the Pickering Nuclear Generating Station.

- Spacer Locating and Repositioning (SLAR)

Reactor fuel channels comprise pressure tubes and calandria tubes, separated by spacers (garter springs). In some early reactors, spacers have been found to be out of position. This program is to inspect, locate and where necessary, reposition these spacers. This is not a problem for newer reactor designs such as Bruce B and Darlington.

These three programs may apply to individual nuclear generating units, depending on the original equipment design, materials used, experience gained from the rehabilitation, and a better understanding of the mechanism that defines fuel channel lifetimes.

Figure 10–7 is a preliminary schedule for the fuel channel rehabilitation work illustrating the capacity outages expected during the winter peak periods from 1989 to 2014.

Nuclear Plant Life Assurance

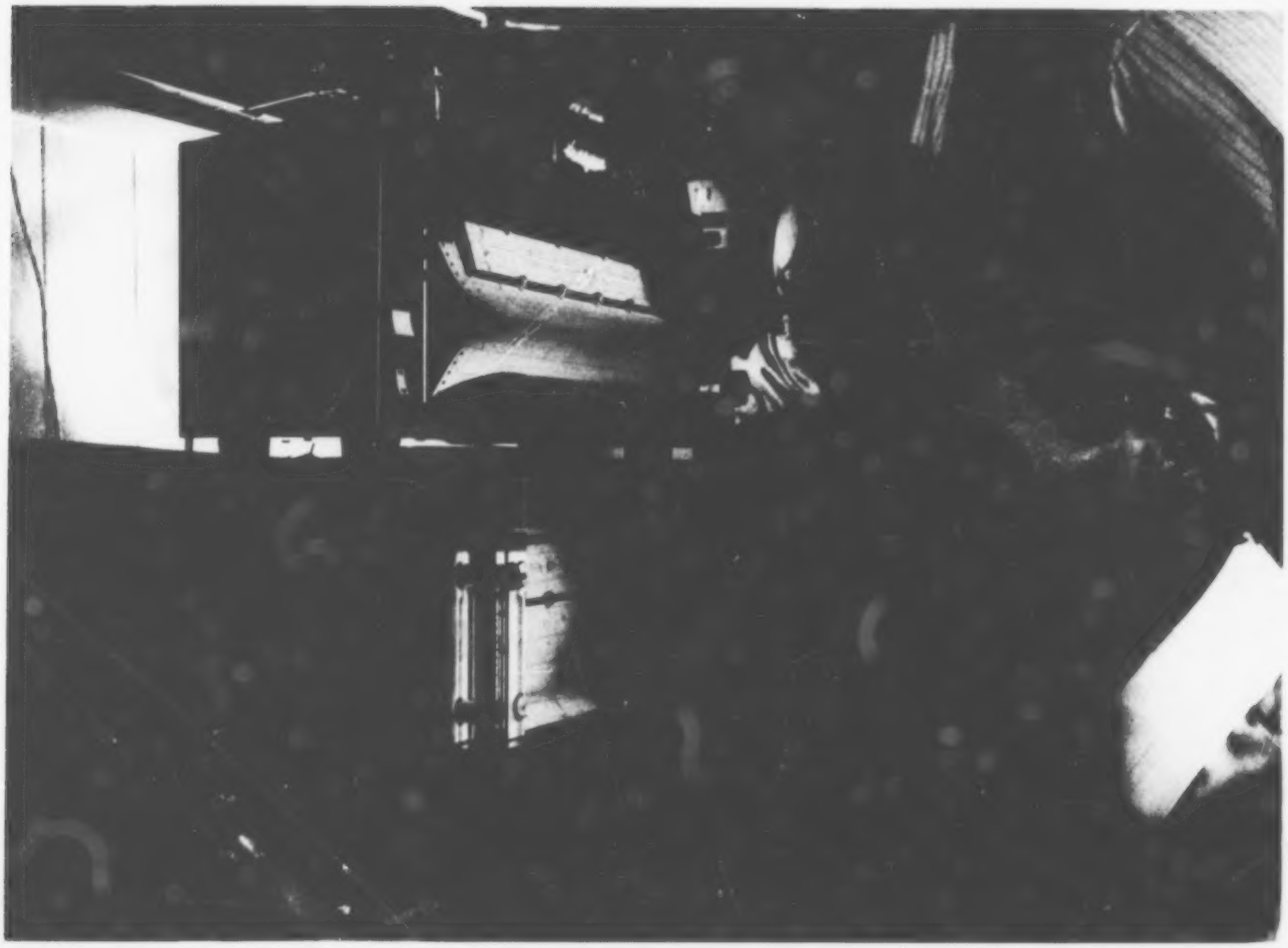
A Nuclear Plant Life Assurance program is underway to identify specific projects (in areas other than fuel channels) to ensure the expected service life of nuclear generating units.

The following are three examples of this life assurance program:

Nuclear units in the U.S. and other countries have required replacement of steam generators. Hydro's CANDU steam generators have performed well to date. Rehabilitation of these steam generators may be required, although such a requirement has not yet been established.

The replacement of certain control systems will be required prior to the end of the units' operating lives.

Potential improvements in the output of Pickering are being examined, and an increase in capacity by about 100 MW or 3% of the station capacity is a possibility.



Monitoring sulphur dioxide emissions.

A downturn in economic conditions could lower the growth in demand for electricity. One way of responding to lower load growth would be to save fuelling, operating and maintenance costs by placing generating units in protective storage for future use, i.e., mothballed. These units could then be returned to service with one to two years notice, if electricity demand rises.

Mothballed generating units fall into two broad categories:

- Older units nearing the end of their service lives, with high fuelling, operating and maintenance costs, as in the case of Hearn and Keith; and,
- New units with high fuelling costs such as Lennox.

During the generation surplus situation in the early 1980s, the fossil units at Hearn (coal/gas), Keith (coal) and Thunder Bay 1 (coal) were mothballed. These stations are comparatively small, less efficient and require more manpower per MW of capacity than other currently operating fossil stations. The oil-fueled Lennox Generating Station was mothballed in the early 1980's because there was a surplus electricity supply and the relatively high fueling cost of the station.

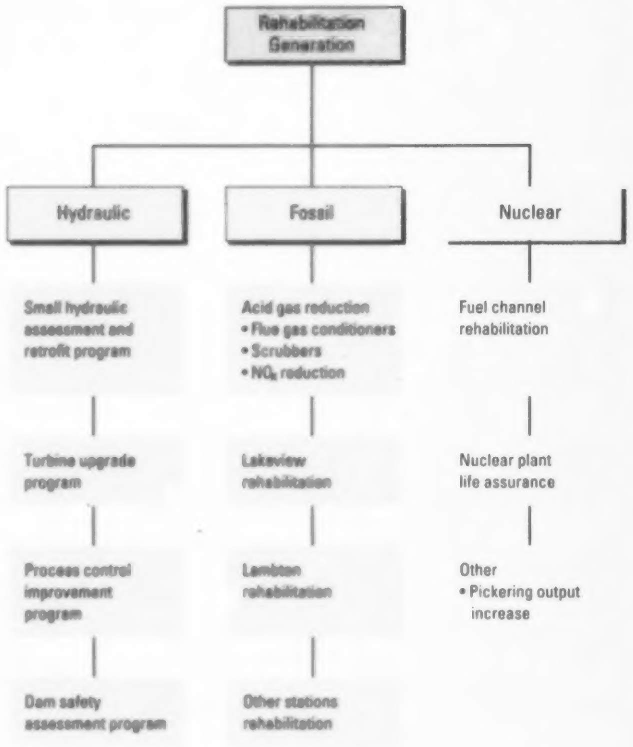
In the near term, mothballed facilities such as Hearn and Keith may not be required for reliable customer load supply under median load growth conditions. However, it may be more prudent to preserve these older facilities in a mothballed state, in order to provide flexibility to meet load in the median to upper growth range, and to cover future uncertainties. These uncertainties and contingencies include change in load growth, fuel supply disruptions, low water conditions and lengthy, unforeseen outages to major equipment. Thunder Bay 1 is located in Northwestern Ontario, where there are transmission limitations, and this may be a factor in the timing of returning the unit to service.

In the demand/supply study cases, the mothballed stations offer Hydro a measure of flexibility, particularly under upper load growth conditions.

The following two examples illustrate the benefits of mothballed generating stations.

The Lennox oil-fueled generating station was mothballed because of its high fuelling costs rather than its age. It is an example of mothballed units providing good system flexibility to respond to changing system conditions. Two 550 MW units were brought back into service within seven months for the 1987/88 winter peak to meet increased electricity demand in the face of capacity and transmission limitations. An additional unit was brought back into service for the winter of 1988/89. The last of the four units is being brought back into service for the winter of 1989/90, as a result of the continuing strong growth in electricity demand, and other system limitations.

Figure 10-8 **Rehabilitation Plan**


Rehabilitation Generation
Hydraulic
Fossil
Nuclear
Small hydraulic assessment and retrofit program
Acid gas reduction
• Flue gas conditioners
• Scrubbers
• NO_x reduction
Fuel channel rehabilitation
Turbine upgrade program
Lakeview rehabilitation
Nuclear plant life assurance
Process control improvement program
Lambton rehabilitation
Other
• Pickering output increase
Dam safety assessment program
Other stations rehabilitation

Programs	**Preliminary Start**	**Completion**	**Remarks**
Hydraulic Generation			
Small Hydraulic Assessment & Retrofit Program	1988	20 years	37 small stations; rehabilitate 2 per year.
Turbine Upgrade Program	1974	Ongoing	51 units upgraded with 272 MW extra to-date; some 67 units may be considered for upgrades.
Process Control Improvement Program	1989	10 years	Improve reliability & better utilize water for generation.
Dam Safety Assessment Program	1986	10 years	Aside from the hydraulic stations, there are some 280 associated hydraulic structures.
Fossil Generation			
Acid Gas Reduction			
Sulphur Dioxide:			
Flue Gas Conditioners for use with low sulphur coal	1990	to 1994	Work authorized for Lambton, Nanticoke and Lakeview.
Scrubbers	1994	Ongoing	First pair of scrubbers in-service in early 1994 on two Lambton 500 MW units. Other units could be retrofitted as required to meet load.
Nitrous Oxide:	1985–87	mid/late 1990s	Nanticoke has been fitted with low NOx burners. Further combustion process modifications being planned for Nanticoke and other large fossil stations.
Lakeview Rehabilitation	1990	to 1994	Project authorized & work is underway to rehabilitate all 8 units (2286 MW) for continued operation to 2006.
Lambton Rehabilitation	1992	to 1995	Study underway to identify rehabilitation work to ensure 40-year life of the station (2100 MW).
Other fossil stations		mid to late 1990s	Specific programs to be developed to ensure 40-year life of the stations.

Figure 10–9 Rehabilitation Plan [illegible]

Programs	Preliminary Start	Completion	Remarks
Nuclear Generation			
Fuel Channel Rehabilitation			
Pickering 1 & 2	Completed		Units are back in-service.
Pickering 3 & 4	1989	to 1991	Work is staged to minimize the number of units out-of-service at any given time.
Bruce 1–4	1990	to 2007	
Pickering 5–8	1991	to 2011	
Bruce 5–7	2009	to 2013	
Nuclear Plant Life Assurance	On-going		Specific programs to be developed to ensure 40-year life of nuclear stations.
Other	On-going		Control system. There may be a need to rehabilitate steam generators. Potential output increase of the Pickering units.

Note: All schedules are preliminary, and these will be refined as the scope of work is better defined.

The mothballed 1,180 MW Hearn station in Toronto and the 256 MW Keith station in Windsor provide insurance against continuing strong load growth, and other system contingencies. Current estimates of the lead time to return a few of the large Hearn units back into service is about 12 to 18 months.

The Hearn station, which can operate on gas, also provides a contingency measure for meeting acid gas emissions, when operation of the coal-fueled station is restricted by the acid gas regulation.

REDEVELOPMENT

Redevelopment, by definition, is not a part of rehabilitation. Redevelopment is the reuse of an existing site with a new generating facility or development of a new facility for the continuing use of an existing hydraulic resource.

Many of the hydraulic options identified in the Hydraulic Plan are redevelopments, as outlined in Chapter 12. Redevelopment may involve increasing the site generating capacity. Ongoing studies will identify the need for redevelopment, by rebuilding, or extending the existing generating stations, or by locating additional generation facilities elsewhere on the river system.

Redevelopment on existing sites is considered in the Supply Plan discussed in Chapter 15.

Redevelopment will be considered and evaluated along with other demand/supply options for meeting future energy demand when generation facilities become technically or economically obsolete. Redevelopment may provide a number of benefits including lower costs; shorter lead times; and maximum use of existing resources such as water, land, transmission lines, rights-of-way and buildings.

A summary of the rehabilitation plans for the existing hydraulic, fossil and nuclear generation facilities is provided in Figure 10–8. The elements of the rehabilitation plans are tabulated in Figure 10–9.

Chapter 3 Basic Load Forecast → **Chapter 4** The Existing System → **Chapter 5** Requirement for Demand/Supply Options → **Chapter 6** Costing Concepts and Avoided Costs → **Chapter 7** The Demand Management Plan → **Chapter 8** The Non-utility Generation Plan → **Chapter 9** The Primary and Firm Load Forecasts → **Chapter 10** Rehabilitation Plan

11 REQUIREMENT FOR NEW SUPPLY

The purpose of this chapter is to discuss the requirements for new supply options by comparing the Firm Load Forecast derived in Chapter 9 with the load-meeting capability of the existing system which is established in Chapter 4.

The future system must have sufficient load-meeting capability to meet the Firm Load Forecast.

Median Forecast: New Supply Requirements by 1997

Figure 11-1 shows the median Firm Load Forecast, plotted together with the load-meeting capability of the existing system. The Figure shows the growing requirement for new supply. That requirement is derived by subtracting the capability of the existing system from the Firm Load Forecast. Demand begins to exceed supply in 1997.

In Chapter 5 the need date for demand/supply options is established as 1993 for the median forecast. Demand-reducing options defer the need for new supply options by four years to 1997.

Upper and Lower Forecasts:

Figures 11-2 and 11-3 show the required new supply for the upper and lower forecasts.

The requirement for new supply options is particularly urgent with upper load growth.

Required Supply – Capacity

Required supply, shown in Figure 11-1, identifies peak power demand to be met by new supply. But the load-meeting capability of supply options requires a reliability reserve, as explained in Chapter 4.

Figure 11-4 shows how the required supply capacity incorporates a reliability reserve added to the required supply load-meeting capability. The required supply capacity grows to two GW by the year 2000, to 13 GW by 2010, and to 19 GW by 2014.

Figure 11-5 summarizes required supply capacity for selected years under the forecast bandwidth. These requirements include the reliability reserve.

Figure 11-6 shows the required supply capacity for the forecast bandwidth.

Required Supply – Energy

Required energy supply for the median forecast is presented in Figure 11-7. New energy requirements are derived by subtracting the energy-meeting capability of the existing system from the Primary Load Forecast. The required energy supply will be met from new generation, purchases, and redeployment of the existing system.

Figures 11-8 and 11-9 show the required energy supply for the upper and lower load growths.

Figure 11-10 tabulates for selected years the required energy supply for the forecast bandwidth.

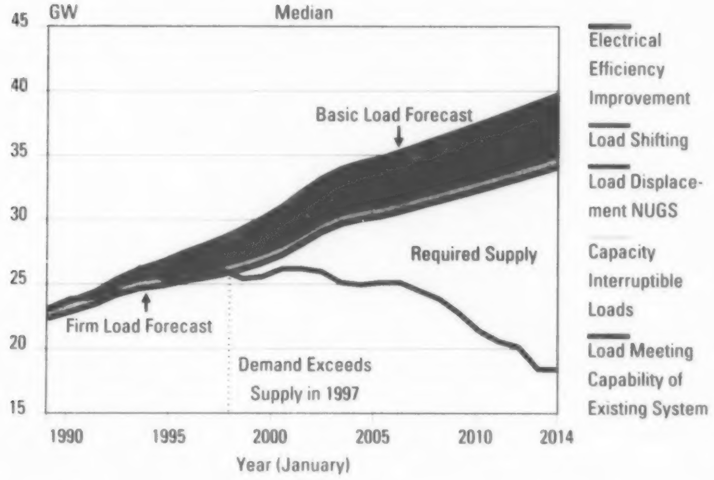


Figure 11–1 **Required Suppy – Peak Power Demand**

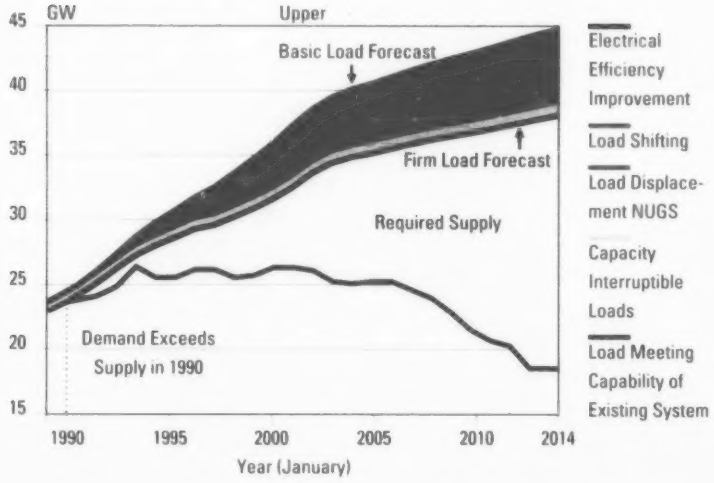


Figure 11–2 **Required Supply – Peak Power Demand**

Demand-reducing options defer the need for new supply options by four years to 1997.

Figure 11–3 **Required Supply – Peak Power Demand**

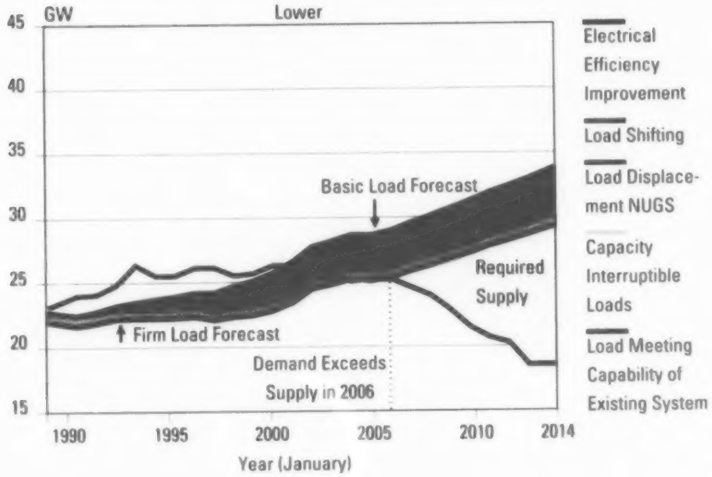


Figure 11–11 shows the required energy supply for the forecast bandwidth.

The next chapter, Chapter 12, will outline Hydro's plans to meet part of the required capacity and energy supply by developing Ontario's remaining economic hydraulic potential. ●

Figure 11–4 **Required Supply Capacity – Peak Power Demand**

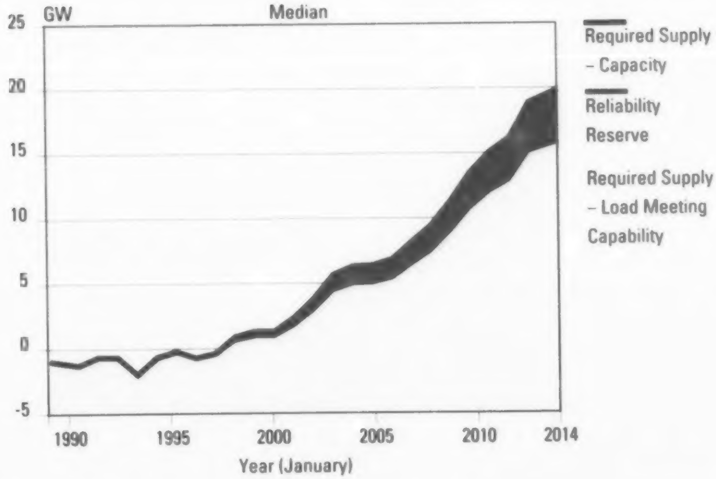


Figure 11-5 **Required Supply – Capacity (GW)**
(includes reliability reserve)

Year	Lower Load Forecast	Median Load Forecast	Upper Load Forecast
1990	0	0	0
1995	0	0	3.8
2000	0	1.6	6.7
2005	0	6.3	12.1
2010	7.0	13.4	18.6

Figure 11–6 **Required Supply Capacity – Peak Power Demand**

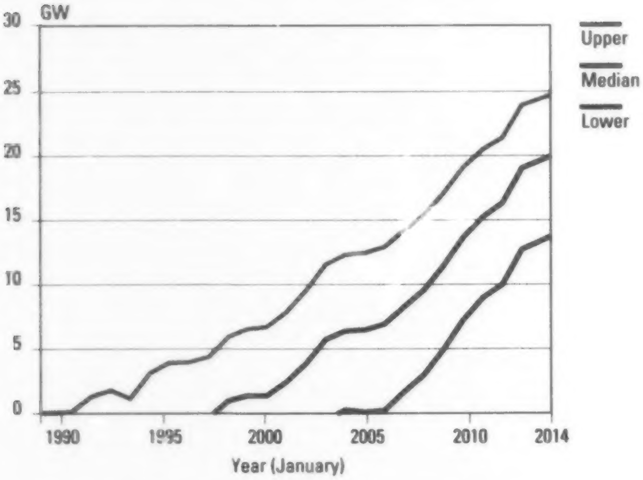
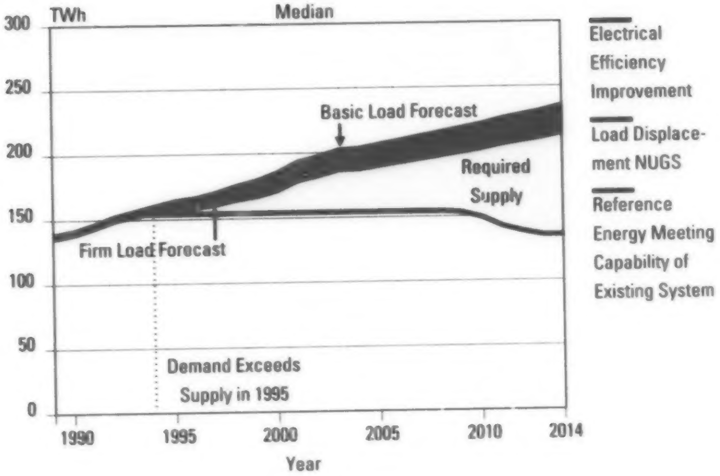
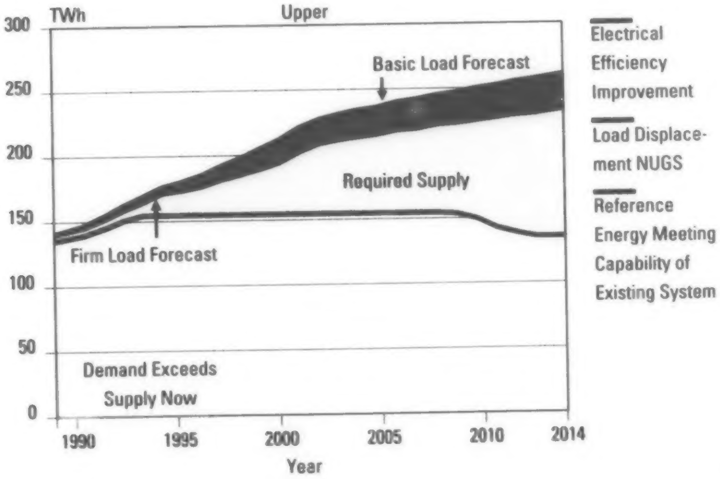


Figure 11–7 **Required Supply* – Annual Energy Demand**



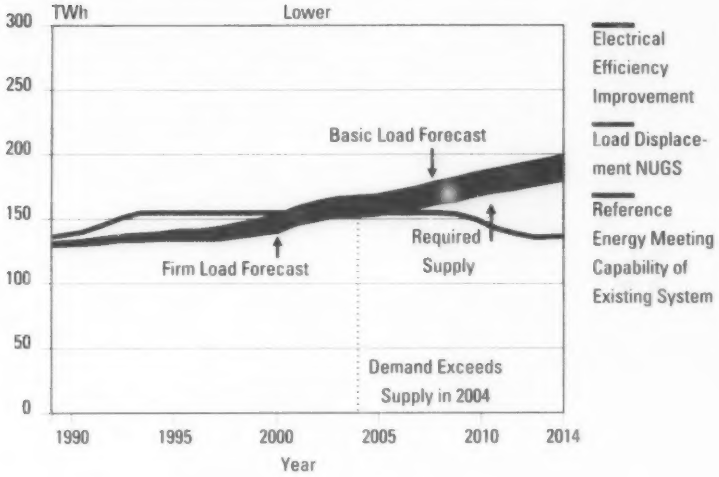
* To be met by new supply options and redeployment of the existing system

Figure 11–8 **Required Supply* – Annual Energy Demand**



* To be met by new supply options and redeployment of the existing system

Figure 11–9 **Required Supply* – Annual Energy Demand**



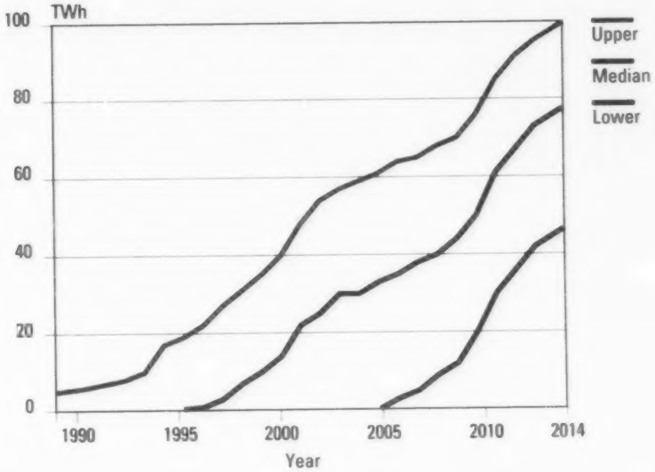
* To be met by new supply options and redeployment of the existing system

Figure 11–10 **Required Supply – Energy (TWh)**

(from new supply and redeployment of existing system)

	Lower Load Forecast	Median Load Forecast	Upper Load Forecast
1990	0	0	5.9
1995	0	2.8	18.7
2000	0	16.0	40.8
2005	0.7	34.4	61.5
2010	21.0	51.7	77.3
2014	45.6	77.6	98.6

Figure 11–11 **Required Supply* – Annual Energy Demand**



* To be met by new supply options and redeployment of the existing system

Chapter 3
Basic Load
Forecast

Chapter 4
The Existing
System

Chapter 5
Requirement for
Demand/Supply
Options

Chapter 6
Costing Concepts
and
Avoided Costs

Chapter 7
The Demand
Management
Plan

Chapter 8
The Non-utility
Generation
Plan

Chapter 9
The Primary
and Firm
Load Forecasts

Chapter 10
Rehabilitation
Plan

Chapter 11 Requirement for New Supply
Chapter 12 The Hydraulic Plan
Chapter 13 Requirement for Major Supply
Chapter 14 Major Supply Options
Chapter 15 Major Supply Plans
Chapter 16 Avoided Cost Determination
Chapter 17 Demand/Supply Plans
Chapter 18 Action Plans

Water power has a prominent role in Ontario's history. Years ago, water-powered mills assisted in agricultural and industrial production. As urbanization and technology progressed, favourable sites were converted to produce electrical rather than mechanical power.

Since 1898 when DeCew Falls Generating Station was built, hydraulic stations have provided Ontario with a low-cost, renewable supply of electricity. The creation of the Hydro-Electric Power Commission of Ontario in 1906, now Ontario Hydro, recognized the importance of the public ownership of low-cost hydraulic generation to benefit all the people of Ontario. Until 1951, Ontario Hydro generated electricity exclusively from falling water. So deeply rooted is the link between water and electric power that "hydro" has come to be synonymous with electricity for many people of Ontario.

To the general public, hydraulic generation still remains one of nature's most abundant gifts. An estimated 17% of the surface area of the province is covered by seemingly innumerable lakes and rivers. To be useful for generating electricity, however, a sufficient volume of water has to fall a significant distance to create a viable energy source. Sites in Ontario which offer these characteristics are now very limited because most have already been developed.

While hydraulic generation will contribute significantly to meeting the province's future energy needs, the lack of viable, undeveloped sites will limit the role that further hydraulic generation can play in Ontario. However, as a proven option using a renewable energy source, hydraulic generation continues to be attractive and it is therefore being given a high priority in Ontario Hydro's planning.

The Hydraulic Plan set out below describes the commitment Hydro is making to the orderly development of hydraulic sites in Ontario within the limits of economic, technical, environmental and social acceptability. Ontario Hydro is already well underway with plans for developing the first eight hydraulic sites in the Plan, which will provide 1,076 MW of capacity by 1998.

The smoothing of resource requirements is an important element in Hydro's orderly development plan. The plan provides a reasonably smooth flow of design and construction work, thereby contributing to lower costs and more stable economic benefits in northern Ontario.

The key operating characteristics of a hydraulic station, its capacity and its annual energy production, are determined by the natural site characteristics. Capacity and energy are a function of the available water flow and the difference in elevation between the headwater and tailwater, i.e. the hydraulic head. As a

Ontario Hydro is already well underway with plans for developing the first eight hydraulic sites in the Plan, which will provide 1,076 MW of capacity by 1998.

result, all hydraulic generation is site-specific and few generic hydraulic station characteristics can be meaningfully defined.

Water, the fuel of a hydraulic plant, can be used at the rate supplied by the river with turbine-generators sized for the average river flow. This is known as "run-of-the-river†" operation, which provides little control over when the energy is produced.

Most of the sites earmarked for future development, however, will be more suited as peaking plants, which have an installed capacity much higher than the average river flow would normally permit. Peaking plants store water behind a dam and release it when required, thereby generating energy when it is needed most. At a time of system emergency and power outages, for example due to severe weather, this stored water can also be drawn down to allow continuous power production for several days.

Peaking hydraulic plants provide excellent operational flexibility. Each unit of the plant can be stopped and started relatively quickly, thereby following the minute-by-minute, hour-by-hour changes in system demand. These plants provide the best match in operation with Hydro's nuclear and fossil capacity.

Hydraulic projects are major civil engineering works with large capital requirements. However, they are not technically complex. The lead times required to obtain approval and complete studies and construction range from eight to ten years. These lead times are shorter than lead times for some supply options like nuclear, though longer than lead times for other supply options such as combustion turbine units.

Compared to other supply options, hydraulic plants tend to be capital-intensive. However, they have a long life expectancy – new plants are evaluated based on a 90-year life. They also require much less maintenance than coal and nuclear stations and are inexpensive to operate. Indeed, most plants can be operated by remote control, without on-site supervision. The only fuelling charge is the water rental payments to the provincial government.

Hydraulic generation has high Ontario content in the design, construction and manufacture of equipment and therefore contributes to economic development. Construction activities related to hydraulic developments are highly labour-intensive and can provide significant employment opportunities over many years.

Although hydraulic generation does not produce environmentally hazardous emissions, development of a site does have environmental effects. Hydraulic plants are situated on rivers used by native peoples, cottagers, swimmers, fishermen, industry and local municipalities. These users expect good water quality, as well as adequate water levels and flows for their activities. Flooding from the construction of new dams and fluctuations in flows caused by peaking operation are of particular concern. Native peoples interests, from both a cultural and land claims viewpoint, may also be a factor when considering individual projects.

The creation of a hydraulic dam and reservoir will flood land and change the natural pattern of stream flow and sedimentation, and could cause erosion if not adequately controlled. Flooding may also destroy wildlife habitat and threaten the livelihood of tourist operators. There may be an increase in mercury concentration in fish in the upstream reservoir as a result of bacterial action on naturally occurring mercury in the flood zone. On the other hand, the creation of a reservoir could help control flooding and erosion problems, and provide new habitats for waterfowl.

The construction of access roads and transmission corridors will have environmental effects but could open up new opportunities such as tourism and recreation.

As demonstrated above, the development of hydraulic potential can have both positive and negative impacts. As a responsible user of a river, Ontario Hydro must study the effects of hydraulic development carefully, to ensure that it will, on balance, provide net benefits for the people of Ontario. Hydraulic developments will be subject to project specific assessments when approval for the project is sought. At that time, the potential impacts will be evaluated and site-specific mitigation measures will be identified.

[illegible]

Ontario's total theoretical hydraulic power potential is 19,900 MW of capacity and 82.8 TWh of average annual energy. Of these totals, 7,500 MW or 38% of capacity, and 38.5 TWh or 46% of energy, have been developed. This leaves 12,400 MW of capacity and 44.3 TWh of annual energy as the undeveloped potential. Generally, the densely populated and industrialized regions with high electricity demand have had most of their hydraulic potential developed. More sparsely populated areas hold most of the remaining undeveloped potential.

It is not practical to develop most of this potential because of technical, environmental and economic considerations discussed below.

Small Hydro

Water power in Ontario had its roots in "small hydro." Over time, economies of scale led to the development of large, centralized hydraulic generating stations, leaving small hydro development relatively untapped. Now that the large hydraulic sites have been substantially developed, there has been renewed interest in small hydraulic developments. The small hydro potential – generally those new sites with under five MW of installed capacity – is best developed by the non-utility generation industry. These projects can have relatively low capital costs and short lead times. In the aggregate, they represent many millions of dollars worth of economic activity and a base for increased exports of products and services related to small hydro technology.

The turbine hall of a small hydraulic station.

Hydraulic developments will be subject to project specific assessments when approval for the project is sought. At that time, the potential impacts will be evaluated and site-specific mitigation measures will be identified.

Sites of under five MW capacity represent a theoretical potential of about 1,000 MW of capacity and 5.7 TWh of annual energy. They number in the hundreds across the province and span a wide range of economic feasibility. As discussed in Chapter 8, it is expected that a portion of this potential can be economically developed by non-utility generators over the next 25 years.

Release of Larger Sites to Non-Utility Generators

The Ministry of Natural Resources is responsible for allocating the use of Crown land and associated water rights in Ontario, pursuant to the *Lakes and Rivers Improvement Act* and the *Public Lands Act*.

In 1988, four hydraulic sites were released by the Ministry to private developers. Long Sault Rapids, Yellow Falls, Grand Rapids and Umbata Falls together account for 331 MW of potential capacity, with 1.2 TWh per year of energy. For technical and financial reasons, however, non-utility generators may build smaller capacity stations than would Hydro on these larger sites.

Creation of Parklands

In 1988 the Minister of Natural Resources announced the creation of 53 new provincial parks in which hydraulic developments would no longer be allowed. This had the effect of removing from future development ten large potential hydraulic sites totalling 694 MW in capacity and 2.5 TWh in annual energy.

Environmental, Technical and Economic Constraints

Environmental, technical and economic constraints are all inter-related and cannot be

Hydraulic dams and reservoirs can have an impact on recreational areas.

The Little Jackfish river in north-western Ontario.

considered in isolation. Technical difficulties can often be solved with sufficient engineering effort, and environmental problems mitigated with additional technical and financial support. However, the resulting cost for the project could render it uneconomic.

A large portion of Ontario's theoretical hydraulic potential lies in the far north: the Albany and Attawapiskat Rivers flowing into James Bay, and the Winisk and Severn flowing into Hudson Bay. Their drainage regions are vast and the water flow is high. However, unlike the hydraulic development areas in northern Quebec, the terrain in this area of Ontario is generally flat, the river gradients gentle, and rapids and falls of any significant magnitude rare. In order to develop their hydraulic potential in the absence of sufficient natural gradients, dam construction would have to be substantial and flooding would be extensive. The environmental impacts resulting from either of these activities in the virgin watersheds would be high.

For these reasons, therefore, the northern rivers are not considered practical for inclusion in the current plan, even though they account for 5,000 MW of the undeveloped hydraulic capacity and 21.7 TWh of the yearly energy potential in the province.

Other potential comes from adding extensions to existing generating stations to maximize the hydraulic resources available at the site. For example, four plants on the Ottawa River – Chats Falls, Chenaux, Des Joachims and Otto Holden – could be extended to add 796 MW of peaking capacity to the system. However, the corresponding energy obtainable from these extensions would be in the order of 0.33 TWh per year. The peaking and energy characteristics, together with concerns about fluctuations in flows on a major waterway, exclude these projects from the current practical potential.

Other sites may also be excluded for economic and technical reasons. Some sites, for example, may be situated in an area of uncertain geological soundness. While site conditions could be rectified with sufficient engineering effort, the resulting cost might derail the project on economic grounds. Some remote sites, totalling 988 MW, have been excluded as only limited data is available at this time. Site visits and exploratory drilling would have to be carried out to determine the feasibility of developing these sites. These matters will be addressed during program development.

For environmental, technical and economic reasons, it is estimated that a total of 6,784 MW and 26.8 TWh per year are impractical for consideration within the current plan.

Practical Future Potential

As summarized in Figure 12-1, Ontario's total undeveloped hydraulic potential of 12,400 MW of capacity and 44.3 TWh of annual energy is substantially reduced by the various factors noted above. After deducting the small hydro sites, those released to non-utility developers or designated as parks, as well as the sites excluded by environmental, technical and economic constraints, Hydro will have only limited hydraulic resources to call on for system expansion. This practical potential for development amounts to 3,591 MW capacity, with 8.2 TWh of average annual energy.

	Capacity (MW)	Annual Energy (TWh)	Annual Capacity Factor (%)
Total Theoretical Potential in Ontario	19,900	82.8	47
Developed Sites	7,500	38.5	59
Undeveloped Potential	12,400	44.3	41
Deduct Allowance for:			
Small Hydro	1,000	5.7	65
Larger Sites Released to Private Sector	331	1.2	40
Parkland	694	2.5	41
Northern Rivers (other than small hydro)	5,000	21.7	50
Other Exclusions	1,784	5.1	32
Total Practical Potential for Development by Ontario Hydro	3,591	8.2	26

Hydraulic facilities are site specific and depend on water flow.

HYDRAULIC ECONOMICS

Existing hydraulic generation is Ontario's source of lowest cost electricity. This has tended to influence public perception with regard to the potential for new hydraulic developments. Detailed studies, however, show the cost of most new undertakings to be high, since the best and most economic sites have already been developed.

In order to rank potential hydraulic sites in terms of cost, a suitable measure is needed. The concept of avoided cost is appropriate for this purpose. Costs can be framed in a more meaningful way by levelizing, or spreading, them over the lifetime energy generated and expressing them in terms of cents per kilowatt-hour. The concepts of avoided cost and levelizing are discussed in Chapter 6.

							Water Rental Included		Water Rental Excluded	
Site	River	Installed Capacity (MW)	Annual Energy (TWh)	Annual Capacity Factor (%)	Levelized Avoided Cost (LAC) (1989 ¢/kWh)	Water Rental (1989 ¢/kWh)	Levelized Life Cycle Cost (LCC) (1989 ¢/kWh)	Cost/ Benefit Ratio (LCC/LAC)	Levelized Life Cycle Cost (LCC) (1989 ¢/kWh)	Cost/* Benefit Ratio (LCC/LAC)
(A) Sites in Definition Phase										
Lake Gibson (N)	Welland	5	0.040	91	3.7	0.16	2.9	0.78	2.8	0.74
Big Chute (R)	Severn	10	0.058	66	4.3	0.20	3.6	0.84	3.4	0.80
Mattagami Complex:										
Kipling (E)	Mattagami	68	0.093	16						
Smoky Falls (R)	Mattagami	182	0.508	32						
Harmon (E)	Mattagami	68	0.097	16						
Little Long (E)	Mattagami	61	0.067	13						
		379	0.765	23	6.1	0.43	5.3	0.88	4.9	0.80
Little Jackfish (N)	Little Jackfish	132	0.568	49	4.8	0.24	5.1	1.05	4.9	1.00
Niagara (E)	Niagara	550	1.441	30	5.3	0.35	3.5	0.65	3.1	0.58
Total in Definition Phase		1076	2.872	30						

In this way, the project life cycle costs of building and operating a station can be compared with the avoided costs associated with major supply plans. A ratio of the project life cycle cost to avoided cost less than or equal to a value of one signals an economically attractive project. These ratios, called cost/benefit ratios, are shown in Figure 12–2 for sites selected for inclusion in the Hydraulic Plan.

A note of caution applies to the use of the levelized costs in Figure 12–2. While it is appropriate to compare the levelized life cycle cost of a project with its corresponding levelized avoided cost for the purposes of ranking, it would not be meaningful to compare the levelized life cycle costs of different projects unless those projects being compared have the same annual capacity factors.

To enable comparisons to be made with other options on an equal footing, a common in-service year must be assumed. The results in Figure 12–2 are based on the year 2002.

Levelized costs and cost/benefit ratios, with and without water rental, are shown in Figure 12–2. Water rental is shown separately and ranges from 4% to 11% of the project life cycle cost.

Individual project costs include the cost of radial transmission to connect the new generating station to the transmission system. However, development of a group of hydraulic facilities in northern Ontario will also necessitate building additional inter-area transmission facilities at a cost of over $200 million (1989$), which is not included in the site specific evaluations. This cost represents about 5% of the cost of the Hydraulic Plan discussed below.

The Hydraulic Plan was developed after consideration of many factors, including electricity demands in different regions, power and energy potential, location (on the river and within the province), technical feasibility, project economics, transmission requirements and environmental impact. Not all sites identified

[illegible]

							Water Rental Included		Water Rental Excluded	
Site	River	Installed Capacity (MW)	Annual Energy (TWh)	Annual Capacity Factor (%)	Levelized Avoided Cost (LAC) (1989 ¢/kWh)	Water Rental (1989 ¢/kWh)	Levelized Life Cycle Cost (LCC) (1989 ¢/kWh)	Cost/ Benefit Ratio (LCC/LAC)	Levelized Life Cycle Cost (LCC) (1989 ¢/kWh)	Cost/ Benefit Ratio (LCC/LAC)
(B) Sites in Concept Phase										
Abitibi Complex:										
Abitibi Canyon (E)	Abitibi	463	0.111							
Otter Rapids (E)	Abitibi	174	0.043							
Nine Mile Rapids (N)	Abitibi	295	0.726							
		932	0.880	11	7.5	0.84	8.4	1.12	7.6	1.00
Renison (N)	Moose	135	0.555	47	4.4	0.24	4.9	1.13	4.7	1.08
Ragged Chute (R)	Montreal	98	0.177	21	6.2	0.47	6.7	1.08	6.2	1.01
Patten Post (N)	Mississagi	250	0.379	17	6.1	0.55	7.4	1.23	6.9	1.14
Blacksmith Rapids (N)	Abitibi	140	0.369	30	5.2	0.34	6.8	1.32	6.5	1.25
Sand Rapids (N) and Allan Rapids (N)	Abitibi	262	0.703	31	5.2	0.34	8.2	1.59	7.9	1.53
Cypress Falls (N)	Mattagami	42	0.106	29	5.1	0.36	8.7	1.69	8.3	1.62
Total in Concept Phase		1859	3.169	19						
Total Program		2935	6.041	23						

(N) = New, (R) = Redevelopment, (E) = Extension

Notes:

1. Levelized life cycle cost and avoided cost assume a common in-service year of 2002 for all sites.

2. Capacity, energy and capacity factor are incremental for plant extension.

3. Levelized life cycle cost includes all capital, operating and maintenance costs. It is shown both with and without water rental.

4. Do not compare levelized life cycle costs among sites having different annual capacity factors.

5. Assumes water rentals commence 10 years after in-service date.

under the practical potential are included in the Hydraulic Plan. Approximately 656 MW with 2.1 TWh of annual energy have been excluded from the Plan because they do not satisfactorily meet some of the above criteria at the present time. The Hydraulic Plan relative to the hydraulic potential in Ontario is shown in Figure 12–3.

Several sites with life cycle costs higher than currently estimated avoided costs are included in the Plan because their development could become attractive in the future. By having these sites in the Plan, more detailed studies can proceed to determine whether these sites warrant development in the future.

The Hydraulic Plan comprises 18 sites: nine new sites, three redevelopments and six extensions totalling 2,935 MW (2.935 GW) of installed capacity, with an annual energy potential of 6.0 TWh. These sites are planned to be developed by 2016.

Figure 12–3 **Capacity (MW)**

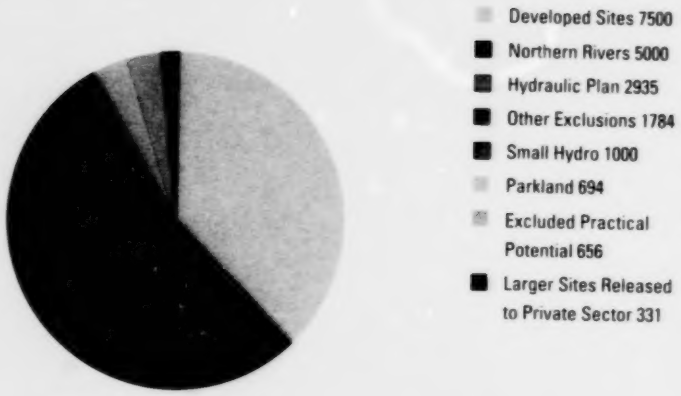
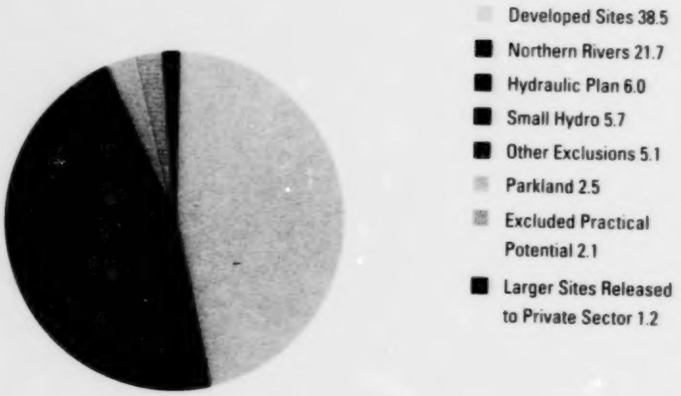


Figure 12–3 **Energy (TWh)**



A careful study of the environmental impact on wildlife habitats is done before building a hydraulic facility.

Figure 12–4 **Hydraulic Plan** Capacity

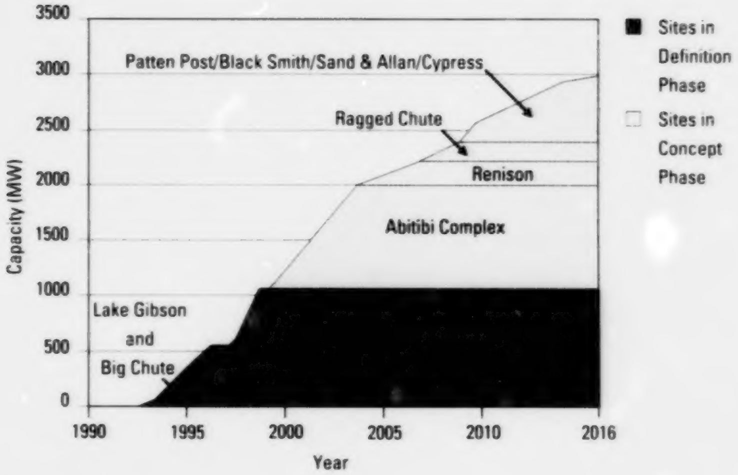
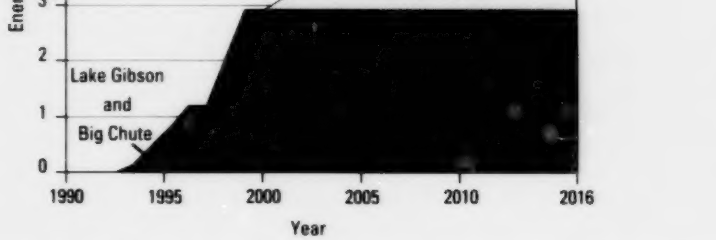


Figure 12–4 **Hydraulic Plan** Energy



Hydro will have only limited hydraulic resources to call on for system expansion.

Because the stations will be designed to maximize the capability of the site, they will not be able to run continuously. The capacity factors for the sites vary widely, from 11% to 91% with an average of 23%.

Figure 12–4 illustrates the capacity and energy increments provided by the Hydraulic Plan over time. Figure 12–5 shows the location of sites within the province.

For median growth, the Hydraulic Plan will provide about 8% of the supply energy requirement and 15% of the capacity requirement by 2014. The total capital cost of all 18 sites in constant 1989 dollars without interest is estimated at $4.9 billion.

Development Sequence

The Plan starts with Lake Gibson and Big Chute which are two smaller developments in Southern Ontario; then a further development of the four-site Mattagami Complex at Kipling, Smoky Falls, Harmon and Little Long; followed by the Little Jackfish development in north-western Ontario and the extension of the Sir Adam Beck station at Queenston on the Niagara River.

Figure 12-5 **Hydraulic Plan Sites**

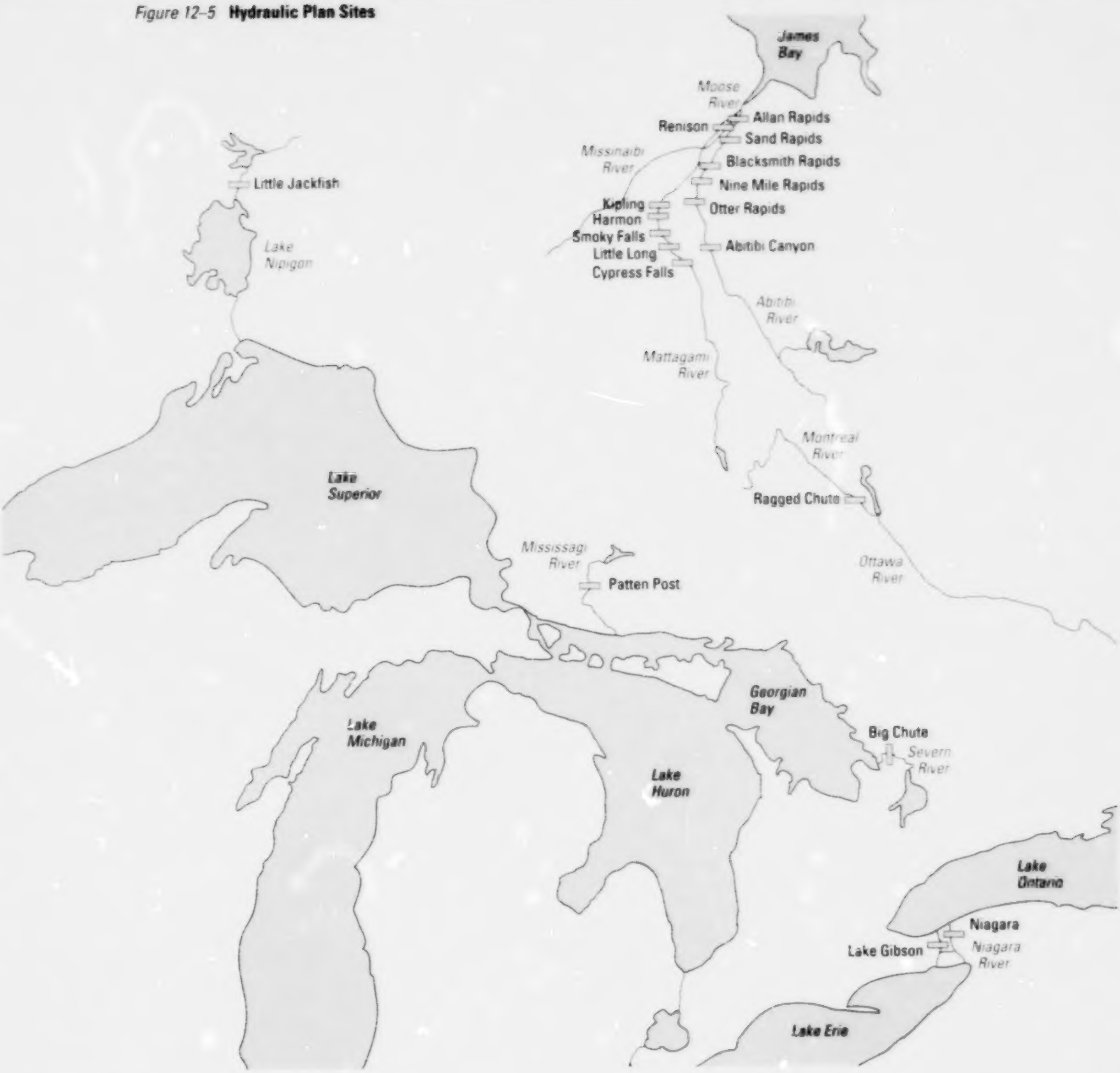
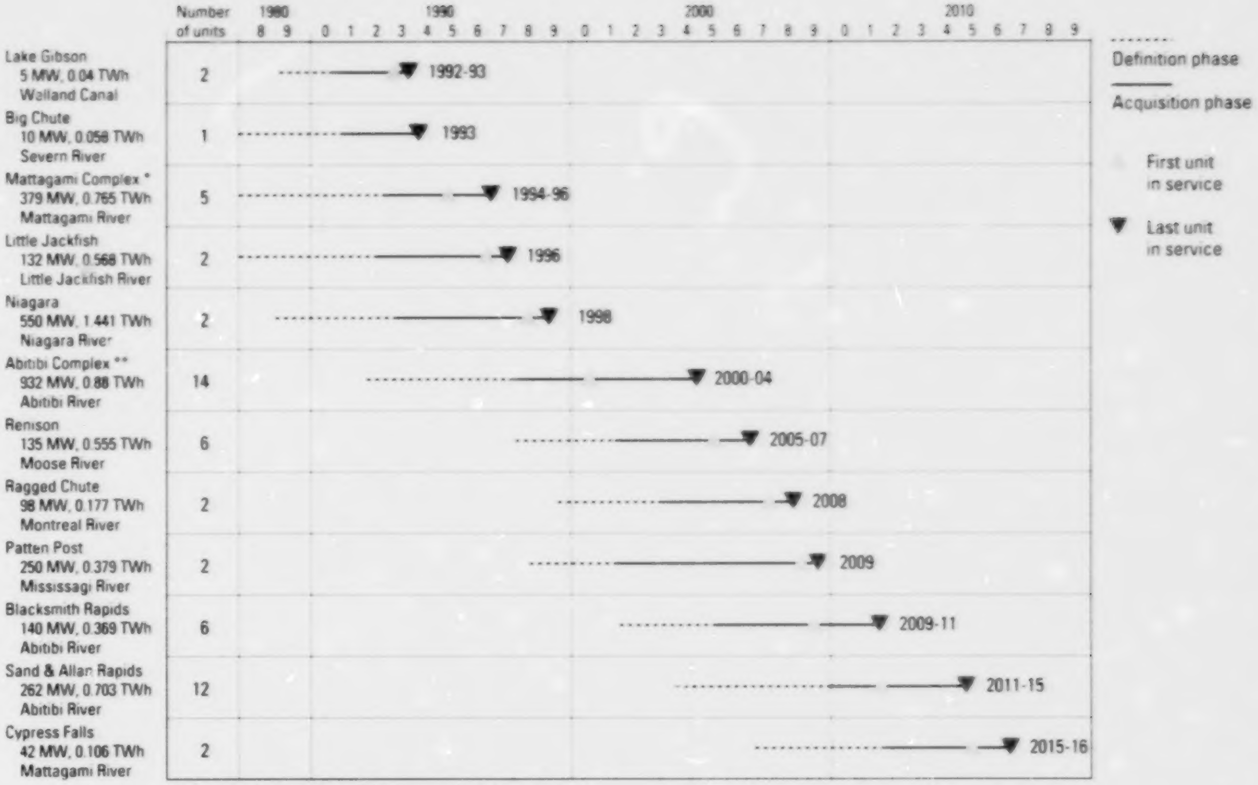

James Bay
Moose River
Allan Rapids
Renison
Sand Rapids
Missinaibi River
Blacksmith Rapids
Little Jackfish
Nine Mile Rapids
Kipling
Otter Rapids
Harmon
Smoky Falls
Abitibi Canyon
Little Long
Lake Nipigon
Cypress Falls
Abitibi River
Mattagami River
Montreal River
Lake Superior
Ragged Chute
Mississagi River
Ottawa River
Patten Post
Georgian Bay
Lake Michigan
Big Chute
Severn River
Lake Huron
Lake Ontario
Niagara
Lake Gibson
Niagara River
Lake Erie

Figure 12-6 **Hydraulic Plan**



* includes Kipling, Smoky Falls, Harmon, Little Long
** includes Abitibi Canyon, Otter Rapids, Nine Mile Rapids

All of these eight sites are currently undergoing detailed engineering, environmental and economic studies – the Definition Phase – to support the project specific environmental assessments, and will provide 1,076 MW capacity and 2.9 TWh of annual energy by 1998.

The Plan then continues with eight sites in the Moose River Basin, which includes the Mattagami, Abitibi and Moose Rivers. Two sites outside the Moose River Basin are included: Ragged Chute on the Montreal River and Patten Post on the Mississagi River. All 10 sites are currently undergoing preliminary technical, economic and environmental feasibility studies – the Concept Phase. Three sites in the Concept Phase, Abitibi Canyon, Otter Rapids, and Nine Mile Rapids, are in a more advanced stage of study than other sites in the Concept Phase. The 10 sites will provide 1,773 MW of capacity and 2.9 TWh of annual energy over the period 2009 to 2014. An additional 86 MW is planned to be developed post 2014.

The Plan gives preference to the development of an entire river basin. This approach

	Definition Phase		Concept Phase		Total All Sites	
	Cumulative Incremental Capacity In-Service MW	Cumulative Incremental Annual Energy In-Service TWh	Cumulative Incremental Capacity In-Service MW	Cumulative Incremental Annual Energy In-Service TWh	Cumulative Incremental Capacity In-Service MW	Cumulative Incremental Annual Energy In-Service TWh
1992	3	0.020			3	0.020
1993	15	0.098			15	0.098
1994	83	0.191			83	0.191
1995	333	0.795			333	0.795
1996	526	1.430			526	1.430
1997	526	1.430			526	1.430
1998	1,076	2.872			1,076	2.871
1999					1,076	2.871
2000			133	0.126	1,209	2.997
2001			333	0.314	1,409	3.186
2002			532	0.503	1,608	3.374
2003			732	0.691	1,808	3.563
2004			932	0.880	2,008	3.751
2005			977	1.065	2,053	3.936
2006			1,044	1.342	2,120	4.214
2007			1,067	1.435	2,143	4.306
2008			1,165	1.612	2,241	4.483
2009			1,438	2.053	2,514	4.924
2010			1,508	2.237	2,584	5.108
2011			1,577	2.418	2,653	5.290
2012			1,642	2.594	2,718	5.465
2013			1,708	2.770	2,784	5.641
2014			1,773	2.945	2,849	5.817
2015			1,838	3.116	2,914	5.987
2016			1,859	3.169	2,935	6.041

A new development at Niagara will produce additional power.

For median growth, the Hydraulic Plan will provide about 8% of the supply energy requirement and 15% of the capacity requirement by 2014.

has major cost, scheduling and approval benefits accruing from the concentration of activities in one region. Sustained activities in the northern part of the province will help to retain a stable, highly trained work force and provide enduring economic benefits to the north over many years.

Most of the proposed hydraulic developments are on rivers with existing developments. This is expected to be environmentally less disruptive than disturbing new watersheds.

CONCLUSION

Ontario Hydro is giving a high priority to the orderly development of the remaining practical hydraulic potential in the province. The Hydraulic Plan schedule of activities is shown in Figure 12–6. The cumulative capacity and energy increments resulting from this schedule of activities are shown in Figure 12–7. Development plans which will provide 1,076 MW of capacity are already underway for the first eight sites in the Plan. An Environmental Assessment document has been previously submitted to the Minister of the Environment for the Little Jackfish project. Co-ordination will be required between the Little Jackfish application and this application in order to avoid unnecessary duplication.

In this application, approval is being requested of the need and rationale for the hydraulic developments which make up the Plan. Subsequent project assessments will focus on ensuring that the individual projects in the Plan are implemented in an environmentally acceptable manner.

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13 REQUIREMENT FOR MAJOR SUPPLY

Chapter 11 describes the requirement for new supply to 2014 before allowing for new hydraulic facilities and purchases from non-utility generation. Chapter 13 describes the requirement for major supply.

This chapter sets out the requirements for capacity and energy with the supply contribution from Hydro's hydraulic and non-utility generation plans taken into account. The requirement remaining after these contributions will have to be met by major supply options.

Chapter 12 discusses the Hydraulic Plan. New hydraulic developments are expected to provide about 2,850 megawatts of capacity, and 5.8 TWh of new energy per year by 2014. Purchases from non-utility generators, as described in Chapter 8, are projected to supply 1,500 MW of capacity and 10.3 TWh of energy by 2014.

Required Major Supply – Load Meeting Capability – Peak Power

Figure 13-1 shows the major supply LMC requirements under the median forecast, after allowing for the LMC contributions from purchased non-utility and hydraulic generation. The requirement is derived by subtracting the load meeting capability of the existing system, hydraulic generation and non-utility generation purchases from the Firm Load Forecast. The figure indicates that the need date for major supply is 2000.

In Chapter 11, the need date for supply options was established as 1997 for the median forecast. Hydraulic and purchased non-utility generation options defer the need for major supply options by three years to 2000.

Figures 13-2 and 13-3 show the required major supply for the upper and lower forecasts. With upper load growth the reliability reserve will decline, and less economic short-term measures may be needed until major supply facilities are put in place.

Required Major Supply – Capacity

Chapter 4 establishes the need for a reliability reserve.

Figure 13-4 shows the range of required major supply capacity, including reliability reserve, to meet forecast demand for selected years under the forecast bandwidth.

Figure 13-5 shows required major supply capacity for the forecast bandwidth.

Required Major Supply – Energy

Chapter 11 introduces the required energy supply for the bandwidth. Figure 13-6 shows how energy from hydraulic and purchased non-utility generation reduces energy requirements under the median load forecast.

Figures 13-7 and 13-8 show the required major energy supply for the upper and lower forecasts.

Figure 13–1 **Required Major Supply – LMC – Peak Power Demand**

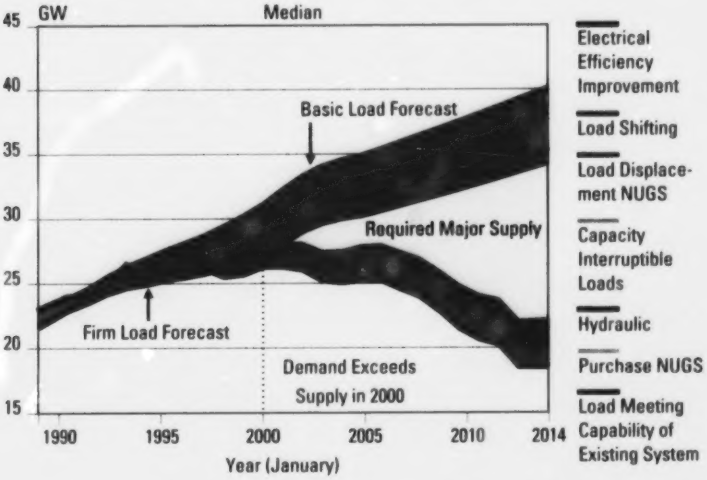


Figure 13–2 **Required Major Supply – LMC – Peak Power Demand**

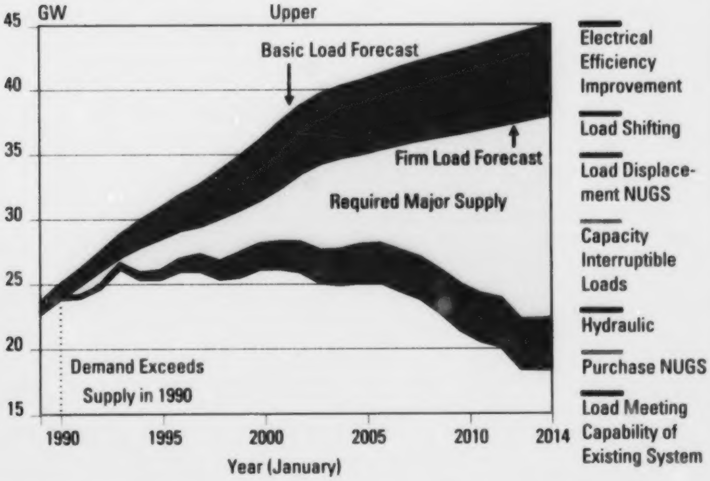
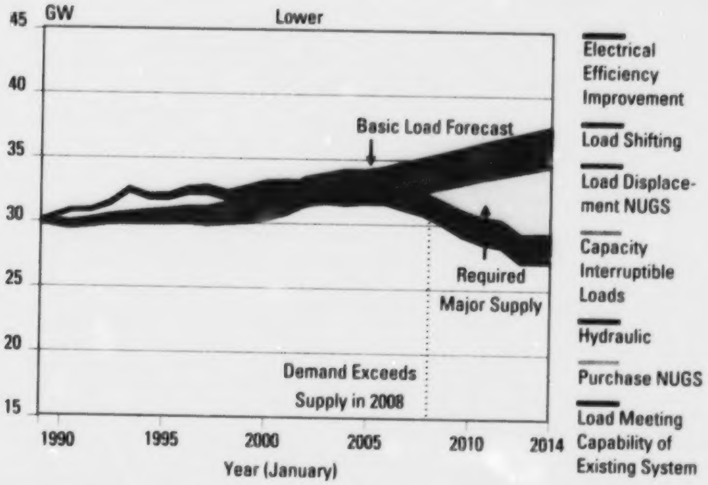


Figure 13-3 **Required Major Supply – LMC – Peak Power Demand**



[illegible] Range of Required Major Supply Capacity (GW)

Year	Lower Load Forecast	Median Load Forecast	Upper Load Forecast
1990	0	0	0
1995	0	0	3.2
2000	0	0	4.6
2005	0	3.1	8.8
2010	3.7	9.5	14.6
2014	9.4	15.0	19.4

Figure 13-5 **Required Major Supply Capacity – Peak Power Demand**

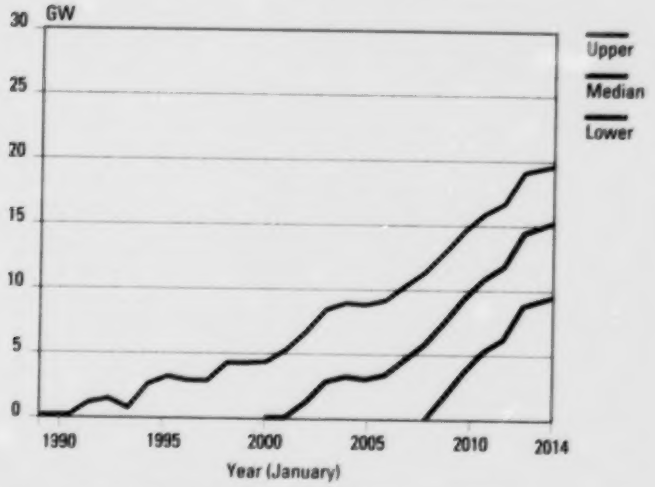
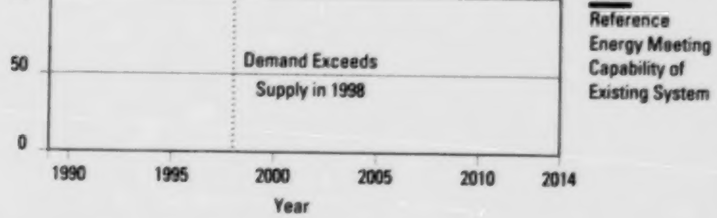


Figure 13-6 **Required Major Supply* – Annual Energy Demand**



*To be met by new major supply options and redeployment of the existing system.

Figure 13–9 gives the quantities of required major energy supply for the forecast bandwidth for selected years. This major energy supply requirement will be met by new stations and purchases, and redeployment of the existing system.

Figure 13–10 shows the required major energy supply for the forecast bandwidth.

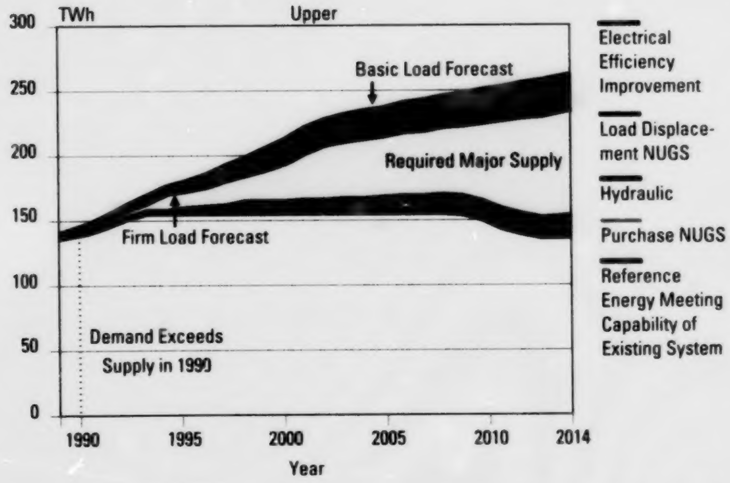
Uncertainty and Action on Major Supply

Hydro's plans for demand management, non-utility generation, and hydraulic development will make valuable contributions to meeting the range of future needs. However, it is clear that these plans will not be enough, and that major supply will be needed to fill the gap between growing demand and Hydro's declining ability to meet customer needs with the existing system.

There is uncertainty as to when the requirement for new major supply capacity will occur. Under the lower forecast, that date is 2008. Under the median forecast, the date is 2000. Under the upper forecast, the province is already facing the need for new supply in addition to the Darlington generating station.

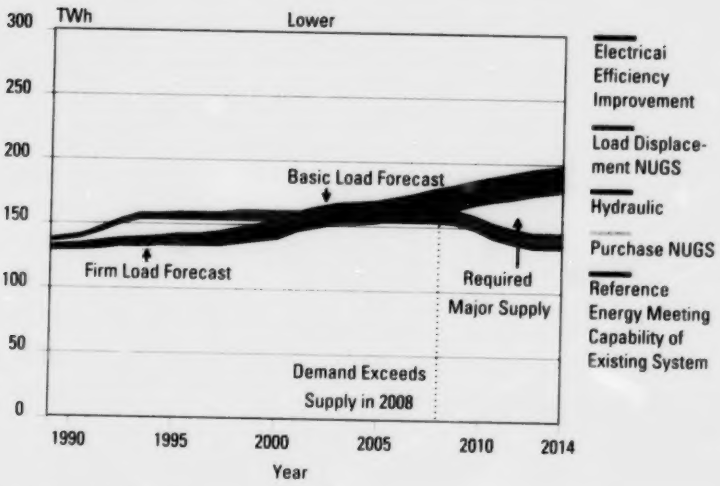
There are also uncertainties concerning the yield from non-utility generation and demand management. Lower contributions from these plans would put greater pressure on the need for more supply, while higher contributions could allow Hydro to defer some major supply plans.

Figure 13–7 **Required Major Supply* – Annual Energy Demand**



*To be met by new major supply options and redeployment of the existing system.

Figure 13–8 **Required Major Supply* – Annual Energy Demand**



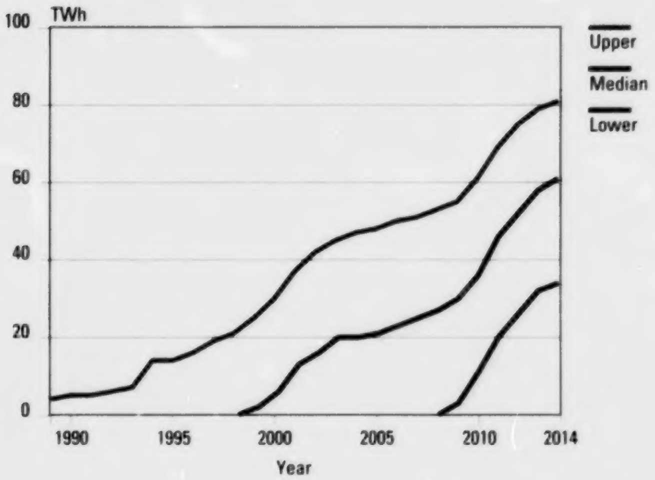
*To be met by new major supply options and redeployment of the existing system.

Figure 13–9 **Range of Required Major Supply Energy (TWh)**

(to be met by major supply and redeployment of the existing system)

Year	Lower Load Forecast	Median Load Forecast	Upper Load Forecast
1990	0	0	5.4
1995	0	0	13.9
2000	0	6.6	30.2
2005	0	22.4	48.3
2010	10.5	37.1	61.5
2014	34.0	61.5	81.6

Figure 13–10 **Required Major Supply* – Annual Energy Demand**



*To be met by new major supply options and redeployment of the existing system

The lead times for major supply options, which will be discussed in the next chapter, must include time for design, approvals, and construction. Some options can be put in place in 2 to 5 years, while other options take 8 to 14. Since long lead time options often have economic and other advantages, planning that restricts itself to short horizons will not result in a balance of options which best serve the long-term electricity requirements of the province.

It is prudent, therefore, to undertake commitments to major supply in a way that allows maximum flexibility to respond to uncertainty. There is a long chain of activities needed to put major supply options in place (design and studies, approvals, construction). Therefore, it is important to move forward with the required design and secure the required approvals, while holding off the commitment to construction until the year of need becomes clearer. Under the median forecast, it is already time to take action.

Deferring construction is possible if load growth takes a downward trend, or if contributions from demand management and non-utility generation materialize quicker than forecast. However, load growth along the upper path could quickly overtake Hydro's ability to respond. Preparatory action for putting major supply into place is required now. ●

Chapter 3 Basic Load Forecast

Chapter 4 The Existing System

Chapter 5 Requirement for Demand/Supply Options

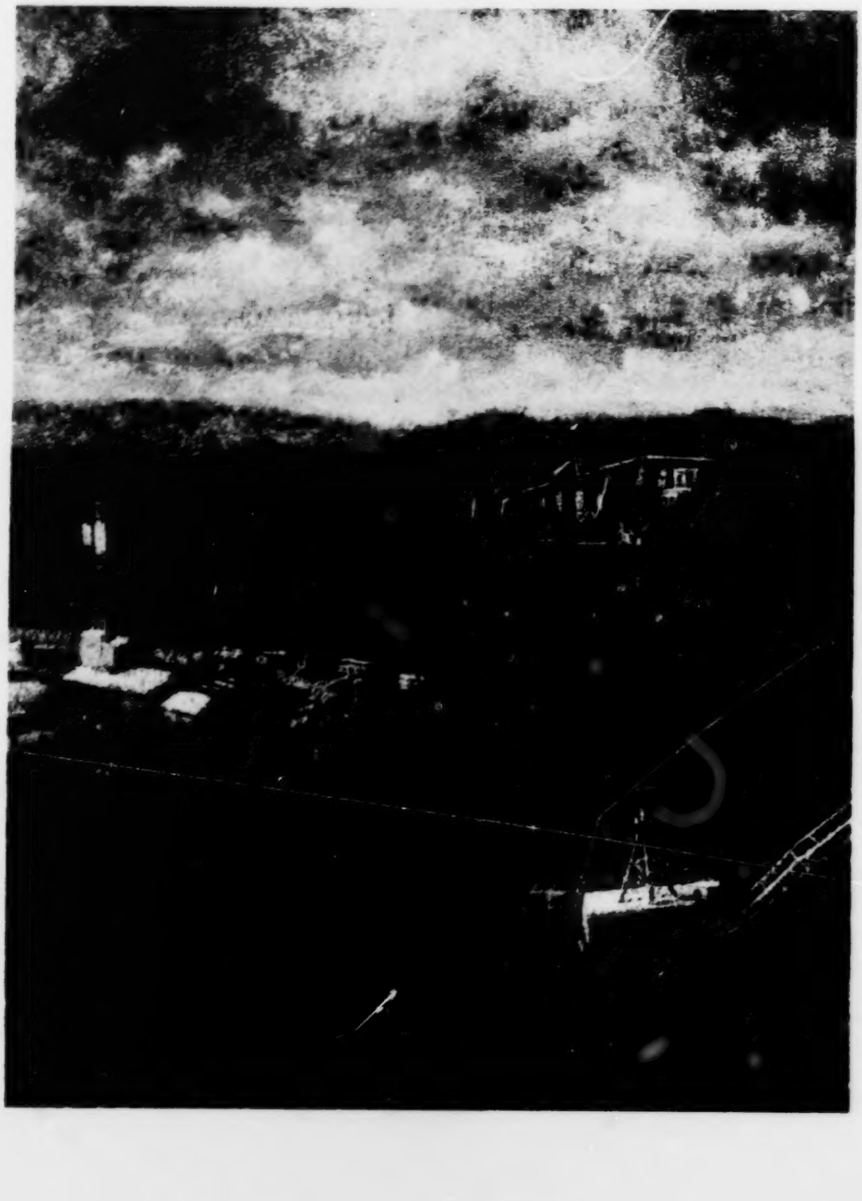
Chapter 6 Costing Concepts and Avoided Costs

Chapter 7 The Demand Management Plan

Chapter 8 The Non-utility Generation Plan

Chapter 9 The Primary and Firm Load Forecasts

Chapter 10 Rehabilitation Plan



14 MAJOR SUPPLY OPTIONS

The purpose of this chapter is to present the major supply options (fossil, nuclear, and purchases) selected for development into plans to meet the remaining requirements identified in Chapter 13.

The process that Hydro followed for option selection is shown in Figure 14–1. The rationale for selection of the options, and siting and transmission considerations are also discussed.

This chapter is divided into the following sections:

- Hydro's review of options 1984–1989
- Components that constitute an option
- Criteria used to evaluate and select options
- Identification of major supply options potentially suitable for plans
- Description and selection of purchase options
- Description of components of fossil and nuclear options
- Characteristics of fossil and nuclear options
- Rationale for selection of options for plan development
- Siting considerations
- Transmission considerations
- Highlights

HYDRO'S REVIEW OF OPTIONS 1984–1989

From 1984 to 1989, Hydro conducted a detailed demand/supply study. Demand and supply options relevant to meeting future electricity needs of Ontario were reviewed.

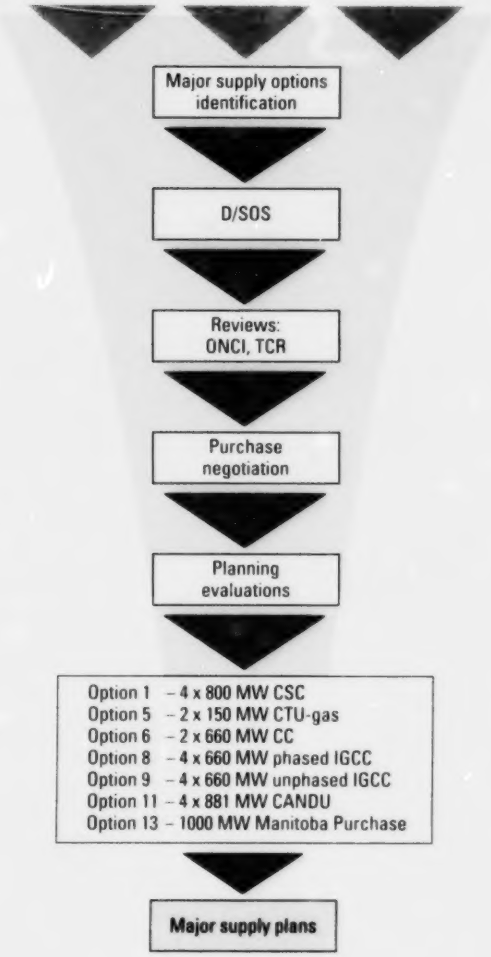
The study included:

- identifying options;
- characterizing options in terms of costs and social implications;
- obtaining broad public input on option preferences and social values pertaining to electricity service; and
- performing representative plan analysis.

Options were initially characterized as to their suitability or unsuitability on the basis of evaluation and selection criteria. The study resulted in the development of the Demand/Supply Planning Strategy, DSPS, in March, 1989. The Strategy contains a set of principles, guidelines and priorities for use in selecting options for plans. A number of supply options are identified in the Strategy as unsuitable at this time for development by Hydro to meet future needs. Among them are solar, wind, wood, peat, waste, and fuel cells. Study of these options showed they were uneconomic for large-scale development.

Despite their unsuitability as major supply options for Hydro, some of these options are suitable for development by non-utility generators or in specific situations where they have advantages. For example, generating electricity by burning municipal solid waste might be developed by municipalities because of its value as a waste disposal opportunity. Wood waste products from the forestry industry could

Figure 14–1 **Process for Selecting Major Supply Options**


Major supply options identification
D/SOS
Reviews: ONCI, TCR
Purchase negotiation
Planning evaluations
Option 1 – 4 x 800 MW CSC
Option 5 – 2 x 150 MW CTU-gas
Option 6 – 2 x 660 MW CC
Option 8 – 4 x 660 MW phased IGCC
Option 9 – 4 x 660 MW unphased IGCC
Option 11 – 4 x 881 MW CANDU
Option 13 – 1000 MW Manitoba Purchase
Major supply plans

present similar opportunities. Hydro forecasts that about 50 MW of wood waste and 100 MW of municipal solid waste generation will be developed by non-utility generators by 2000.

Wind and solar generators can be valuable in communities without access to cheaper centralized power. In these remote communities electricity is generated by expensive local diesel generators. Energy from wind turbines or solar cells, even though it is not available around the clock, can reduce the use of expensive diesel fuel.

The experience Hydro has gained in designing, installing, and operating wind turbines and solar cells has been valuable in understanding these options. Hydro will continue to do research and development on many generation concepts which have promising applications. Hydro is also keeping abreast of research and development by others and is ready to respond if a major technological breakthrough occurs.

Following are some of the inputs to the Demand/Supply Options Study, which preceded the Demand/Supply Planning Strategy.

Public Consultation

Hydro undertook an extensive program of consulting and communicating with customers and the public during late 1985 and the first half of 1986. Consultation featured meetings with 58 provincial organizations, 300 community leaders across the province and 116 municipal utilities. Hydro gathered public and customer opinions, concerns and priorities through consultation meetings, questionnaires, and briefs (see Regional Consultation, Report No. SCS 86003 and Provincial Organization Consultation Program, Report No. SCS 86002/1). This was presented to Hydro's Executive Office, Board of Directors, and other decision makers in the Corporation. In addition, there were regular briefings with elected and appointed officials.

Public Attitude Research

Hydro researched public concerns, perceptions and values related to planning demand and supply options. Detailed customer surveys on a wide range of demand/supply topics were conducted in 1986, using personal interviews with 1200 residential, 200 commercial, and 200 industrial customers. Similar surveys were done in 1988 and the summer of 1989.

Hearings and Reviews

Hydro made a number of appearances before, and submissions to, hearings and reviews. The Ontario Legislature's Select Committee on Energy examined Hydro's Demand/Supply Options Study in 1986, and the draft Demand/Supply Planning Strategy in 1988. The Committee concluded that before making a commitment to a major generating station, Hydro should make every effort to develop the potential of the existing system, demand management, non-utility generation, and remaining hydraulic sites.

Public safety concerns regarding nuclear power were extensively reviewed, most recently in 1987–88 by Dr. F.K. Hare in the Ontario Nuclear Safety Review. It found that Ontario Hydro reactors are being operated safely and at high standards of technical performance.

During 1988–89, the Ontario Nuclear Cost Inquiry, commissioned by Ontario's Minister of Energy, examined and endorsed Ontario Hydro's estimates of CANDU nuclear costs as well as its planning estimate methodology.

In 1989, Hydro's Board of Directors required that an external review be conducted to validate planning cost estimates for fossil-fueled options. The review, known as the Thermal Cost Review, has been accepted by Hydro's Board of Directors.

Options must meet all safety requirements.

COMPONENTS THAT CONSTITUTE AN OPTION

Electricity can be produced from many different primary energies and processes. In planning an electricity system, it is important to consider a number of aspects or components related to the production of electricity by an option.

Primary Energy or Fuel

Every electricity generating option requires primary energy which can be converted into electrical energy. These primary energies include fossil fuels (oil, gas or coal), uranium, or falling water. Purchases from outside the province also utilize primary energy, such as falling water.

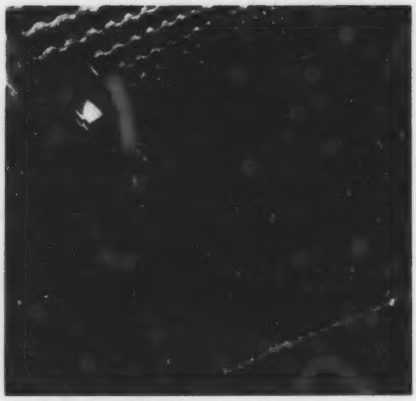
Conversion Process

To produce electricity, primary energy must be converted into electrical energy. For example, heat from the combustion of fossil fuels or nuclear fission is used to produce steam which drives turbines and generators to produce electricity. The efficiency of the conversion process is an important factor in the cost of an option.

Environmental Control

Fossil and nuclear options produce a variety of emissions as a by-product of electricity production. These emissions may take the form of solids, liquids, gases, heat and noise released to the surrounding environment. There are two basic principles used to control emissions: elimination and reduction. Elimination can be accomplished by selecting processes which avoid emissions, use zero discharge systems, or recycle. Where elimination is not feasible, emissions are reduced to meet or improve on requirements established by environmental regulations and to meet Ontario Hydro's standards, which may be stricter than government regulations. Regulatory trends are toward control at source.

Typically, there is a number of emissions produced by major supply options and various systems to control them. For example, the combustion of fossil fuels produces sulphur dioxide (SO_2) and nitrogen oxides (NO_x). These acid gas emissions are currently controlled by the use of low-sulphur coal, low NO_x burners, and properly designed stacks. In the future, these emissions will be controlled by scrubbers and improved combustion techniques. Particulate emissions are typically controlled by electrostatic precipitators that capture fly ash particles before they reach the stack.



How a technology performs depends on well trained workers as well as excellence in design.

In CANDU nuclear stations, a closed circuit is used. In normal operation, there are no significant radioactivity emissions from the process into the environment. The design and operation meets requirements of the Atomic Energy Control Board. This overall approach is called a "contained system."

Configuration

Configuration of an option refers to the number of units per station, the size of each unit and the arrangement and combination of major parts that comprise an option. The cost of each supply option is affected by the configuration.

Multi-unit stations are less costly to design, construct and operate than single unit stations, because of economies derived from standardization. For Ontario Hydro, the number of units at existing stations varies from a single unit to eight units, and one or more stations, on a site.

The size of units also affects costs. Specific capital costs, unit energy costs and specific administration costs of any one generation concept tend to decrease with increasing unit size, due to economies of scale. Unit sizes in the selected options vary from 150 MW combustion turbine units (CTUs) to 881 MW CANDU units.

Some options have the flexibility of phased development. For example, CTUs, if properly arranged, can become the initial part of a combined cycle (CC) station which, in turn, can form the basis of an integrated (coal) gasification combined cycle (IGCC) station.

System Application

A key aspect of an electricity system is how the total customer load, which varies over time, can best be met economically by different options. The electricity system must be able to meet loads which vary hour to hour, day to day, and season to season.

The time variation in load is characterized by classifying load into three types: peak, intermediate, and base, as discussed in Chapter 3.

Each generation option has characteristics that make it suitable for meeting one of the requirements, base, intermediate, or peak load. How each generating unit is utilized depends on such factors as generating unit capability, variable cost, operating characteristics, system limits and reserve requirements. Generating units can be classified as to their utilization to meet system loads. Utilization is expressed as an annual capacity factor (ACF). An 80% ACF, for example, is the equivalent of a unit running at full power for 80% of the year. By this classification, base load units typically operate with an ACF between 60 and 80%; intermediate load units with an average ACF between 20 and 60%; and peaking units with an ACF up to 20%.

CRITERIA USED TO EVALUATE AND SELECT OPTIONS

Criteria for evaluating and selecting options and plans were developed in the Demand/Supply Planning Strategy.

Following are some of the considerations, based on the criteria, which are applied in evaluating the options:

Providing Low-Cost Electricity Service

Ontario electricity users continue to have electricity available at costs lower than most other places in the world. To have cost-effective plans, cost-effective options must be used as components of those plans. Hydro, in taking a leadership role in protecting the environment, aims to achieve "low" rather than "lowest" costs.

Environmental Considerations

Environmental considerations include requirements and standards, which must be met, and environmental characteristics of the option. Environmental considerations are used to both develop and evaluate options.

Global, regional and generic concerns were considered. Project-specific impacts for the major supply options will be dealt with in future project environmental assessments.

Areas considered in evaluations of the natural environment include air emissions, (particularly SO_2, NO_x, CO_2 and radionuclide emissions), water effluents, solid waste (including nuclear waste) and land use.

Environmental considerations are dealt with on a total system basis in the next chapter.

Socio-Economics

Impacts on the provincial economy are also taken into account in assessing the relative advantages of a particular option and fuel source. These impacts include effects on provincial employment and on provincial GDP and balance of trade.

Several other social impacts and benefits cannot be fully addressed, except in the context of site selection and project studies.

Safety

To be considered in the Demand/Supply Plan, all options have to meet safety requirements and standards.

Flexibility

Flexibility is an important criterion because of uncertainties surrounding future load growth, fuel prices, etc. Some options have better ability to respond to changing conditions. Examples of flexibility in an option are shorter lead times and the ability to run on different fuels or at different capacity factors without unacceptable cost penalties.

Resource Preference

Resource preference deals with the source and availability of the primary fuel used by an option. It also considers where equipment might be manufactured. The resource preference principles relevant to major supply options favour:

- renewable energy and the use of waste fuels;
- plentiful fuels over those more likely to be in shorter supply in the long term; and

DSPS Evaluation Criteria

Primary Criteria

The primary criteria (which must be met) for evaluating and developing recommended plans are:

- Customer satisfaction
- Reliability standards
- Safety requirements and standards (worker and public)
- Environmental requirements and standards
- Low cost of electricity service
- Social acceptance
- Technical soundness
- Flexibility

Secondary Criteria

Secondary criteria, which are considered and may influence the recommended plans, include:

- Resource preferences
- Diversity
- Resource smoothing
- Environmental characteristics, in addition to requirements and standards
- Public safety characteristics; in addition to requirements and standards
- Economic impact
- Other social considerations

Secondary criteria, which do involve considerable judgment, have had a significant effect on the evaluation of options and plans.

Decisions on future generating stations will have significant impacts for over 40 years.

- the use of Ontario and other Canadian resources over imported ones.

Technical Soundness

Technical soundness refers to the maturity of an option and the extent of Hydro's experience with it. Mature options, which are used worldwide and are commercially available, are generally considered sound, while developing options with little operating experience may be questioned.

Reliability

All options must meet standards of reliability. Where options differ somewhat in the degree to which they are unavailable for service, these differences are factored into the amount of capacity required to meet load.

There are many factors which contribute to an option's reliability. The way it is operated and maintained is a major contributor to how it performs. Some features of design and construction that can affect reliability include:

- Fundamental design (simpler designs tend to be more reliable than complex ones);
- Unit size (smaller units tend to be more reliable than larger ones);
- Nature and quality of materials used in construction; and
- Type of fuel (cleaner gaseous or liquid fuels help fossil units run more reliably than solid fuels).

Evaluation Criteria

While the above considerations can be applied in evaluating options, there can be no systematic calculation to determine how the criteria are weighed against each other. Judgements about relative performance and how an option's best characteristics can be maximized and worst characteristics minimized are considered later in this chapter.

IDENTIFICATION OF MAJOR SUPPLY OPTIONS POTENTIALLY SUITABLE FOR PLANS

Ten fossil, two nuclear and two purchase options have been identified as potentially suitable for inclusion in plans. The rationale for the selection of the ten fossil options is contained in the Thermal Cost Review. All ten fossil options are equipped with emission control equipment.

The nuclear options selected are limited to the CANDU option. The CANDU option is a Canadian concept which has achieved high performance in respect to worker safety, public safety, environmental protection and reliability. This performance has been achieved at low cost. The cost performance was documented in Ontario Hydro presentations to the Ontario Nuclear Cost Inquiry (ONCI), and was confirmed by the finding of that Inquiry.

The two purchase options identified resulted from discussions and negotiations with neighbouring utilities.

These 14 major supply options, grouped by conversion process, are shown in Figure 14–2.

DESCRIPTION AND SELECTION OF PURCHASE OPTIONS

The Demand/Supply Planning Strategy states:

> "6.2 Long-term firm purchases of hydraulic power from neighbouring provinces will be considered as an acceptable alternative to building new supply facilities after maximum efforts are made to utilize the cost effective indigenous resources of Ontario."

Ontario Hydro has a dedicated organizational unit responsible for long-term purchases and sales of electricity between Ontario Hydro and neighbouring utilities in the United States, Quebec, Manitoba, and Newfoundland.

Potential for Purchases from the US

In the mid 1970s and early 1980s, load growth in the US was less than had been forecast. This placed many US utilities in a difficult position. Despite some cancellations, these utilities were bringing into service new generation, committed for construction years in advance, but surplus to needs. In many cases, this led to regulatory bodies refusing to allow all or part of the station's costs to be included in the rate base.

In this environment, many utilities were reluctant to commit construction of new generation to meet future demand. It is expected that this may lead to shortages in the US Northeast in the 1990s. Some areas in the Northeast have already experienced shortages over the past few summers. (Reference – 1989 Reliability Assessment, The Future of Bulk Electricity System Reliablitiy in North America 1989–1998)

Of the few utilities that are bringing new generation into service in the next decade, the prices quoted to Ontario Hydro for the sale of part of their new output have been high relative to the cost of building generation in Ontario. The US generation available for sale is primarily gas and coal-fueled. The availability and cost of coal-fueled generation would be vulnerable to acid gas legislation in the US.

Accordingly, because of the uncertainty in the US supply/demand picture and the high cost of purchases, Hydro cannot at this time rely on the US for a reliable and economic supply of electricity.

Quebec Purchase Option

Discussions with Hydro Quebec began in 1985 on possible purchases ranging from 500 to 4000 MW. In July, 1988, Hydro Quebec made an offer to Ontario Hydro of 2000 MW, at an annual capacity factor of 65%, to run from 1998 to 2023. Two prices were quoted:

- a lower price which required Ontario Hydro to share with Hydro Quebec some of the risks of the sale, such as the possibility of load growth differing from forecast, and some financial risks:
- a higher price without risk sharing.

The proposal without risk sharing was about twice as costly as nuclear generation and 1.6 times as costly as coal-fueled generation. The proposal with risk sharing resulted in a price reduction of about 13%.

Hydro Quebec has been informed that the offer is not acceptable. They have advised that substantial reductions in the prices are unlikely. Discussions are continuing, focusing on smaller purchases of a shorter duration on terms that may be more attractive. Purchases from Quebec are not included for plan analysis at this time.

Manitoba Purchase Option

Ontario Hydro contracted with Manitoba Hydro in 1987 a five-year 200 MW purchase, starting in 1998. Since that contract was signed, negotiations with Manitoba Hydro have resulted in an agreement to purchase 1000 MW over about 20 years at up to 80% capacity factor. The levelized unit energy cost (LUEC) of this purchase, at 80% ACF, is about 3.7¢/kWh (1989$). Figure 14–3 shows the timing and amounts of the purchase blocks.

The purchase has several features:

- Its cost is low, approaching that of nuclear generation;
- The purchase and associated transmission provides improved reliability of supply to

Figure 14–2 **Major Supply Options Potentially Suitable for Plans**

Generation Type	Conversion Process	Option	Configuration	Primary Energy	Principal System Application
Fossil	Conventional Steam Cycle (CSC)	Option 1	4 X 800 MW	U.S. Coal	Base
		Option 2	4 X 500 MW	U.S. Coal	Intermediate
		Option 3	4 X 500 MW	Western Canadian Coal	Intermediate
	Combustion Turbine Units (CTU)	Option 4	2 X 150 MW	Oil	Peaking
		Option 5	2 X 150 MW	Gas	Peaking
	Combined Cycle (CC)	Option 6	2 X 660 MW	Gas	Intermediate
		Option 7	2 X 660 MW	Gas	Peaking
	Integrated Gasification Combined Cycle (IGCC)	Option 8	4 X 660 MW	U.S. Coal (Phased)	Variable
		Option 9	4 X 660 MW	U.S. Coal (Unphased)	Base
	Atmospheric Fluidized Bed Combustion (AFBC)	Option 10	4 X 200 MW	U.S. Coal	Base
Nuclear	CANDU	Option 11	4 X 881 MW	Uranium	Base
		Option 12	1 X 450 MW	Uranium	Base
Purchase	Hydraulic	Option 13	1000 MW	Manitoba Purchase	Base
		Option 14	2000 MW	Quebec Purchase	Base

Northern Ontario and results in a more economic operation of the power system; and

- The source of supply is hydraulic generation, a renewable indigenous Canadian resource.

To take delivery of the purchase, Ontario Hydro must build about 1100 km of high-voltage transmission in northern Ontario. Joint studies with Manitoba are underway to develop the best alternative scheme for this transmission. Figure 14–4 shows these new transmission facilities. The precise configuration of that new transmission, including an assessment of viable alternatives, will be considered in a project-specific environmental assessment for the transmission facilities.

The following alternative illustrates the extent of new transmission required in Ontario to incorporate the purchase:

- 150 km of 500 kV single circuit line from the provincial boundary (connected to a Manitoba Hydro line originating in the Winnipeg area) to Dryden transformer station (TS). A 500 kV switchyard with 500/230 kV autotransformers and associated switchgear facilities would be installed at Dryden.
- 300 km of 500 kV single circuit† line from Dryden TS to Lakehead TS in the vicinity of Thunder Bay. A 500 kV switchyard with 500/230 kV autotransformers and associated switchgear facilities would be installed at Lakehead.
- 650 km of 500 kV single circuit line from Lakehead TS to Mississagi TS in the vicinity of Sault Ste. Marie, with 500 kV switching facilities provided at a new transmission station near the mid-point of this line. A 500 kV switchyard with 500/230 kV autotransformers and associated switchgear facilities would be installed at Mississagi TS. Terminating this line in the Timmins area rather than at Mississagi TS will also be considered.
- If the line from Lakehead TS terminates at Mississagi, the existing 500 kV single circuit line, now operating at 230 kV, from Hanmer TS in the Sudbury area to Mississagi TS would be re-insulated and reconductored to make it suitable for 500 kV operation.

Ontario Hydro and Manitoba Hydro have agreed that the transmission lines and associated station equipment in both provinces will be designed and built to carry at least 1500 MW between the two provinces. This higher interconnection transfer capability will provide substantial benefits to both provinces from other types of transactions in addition to the 1000 MW purchase. The additional 500 MW

Figure 14–3 **Staging of Manitoba Purchase – Firm Capacity**

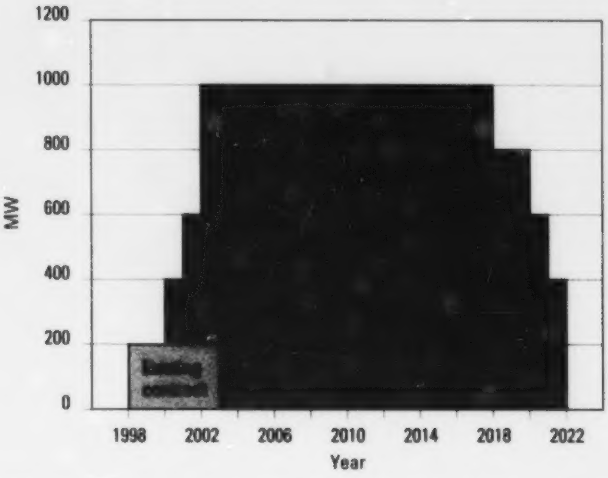
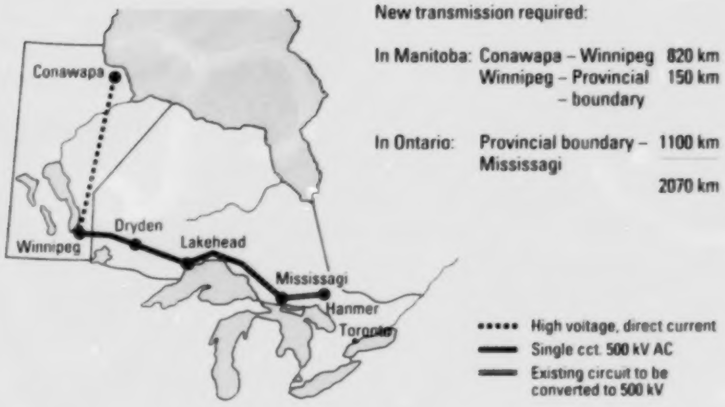


Figure 14-4 **New Transmission Required for Manitoba Purchase**



New transmission required:

In Manitoba:	Conawapa – Winnipeg	820 km
	Winnipeg – Provincial – boundary	150 km
In Ontario:	Provincial boundary – Mississagi	1100 km
		2070 km

- ••••• High voltage, direct current
- ▬ Single cct. 500 kV AC
- ▬ Existing circuit to be converted to 500 kV

Coal, though abundant, varies in cost. Low-sulphur Canadian coal is more expensive than U.S coal due to transportation costs.

capability does not add to the number or length of transmission lines required for the purchase.

The agreement with Manitoba Hydro requires that both parties obtain all necessary environmental approvals and other approvals, including the approval of the respective Boards of Directors of each corporation. There are clauses in the contract which permit cancellation under certain circumstances. One of the cancellation provisions requires Ontario Hydro to make payments to Manitoba Hydro if Ontario Hydro cancels the contract after January 1, 1991 because it has not obtained provincial approvals. Cancellation payments would be based on Manitoba Hydro's out-of-pocket costs, which would escalate significantly after the January 1, 1991 date.

The approvals requested in this application (Chapter 19) currently include approval of the requirement and rationale for transmission facilities required to incorporate the Manitoba purchase. A subsequent project-specific assessment will ensure that the facilities will be located and implemented in an environmentally acceptable manner.

The Manitoba purchase is included in all plan alternatives.

Potential Purchase of Power from Newfoundland

At the First Ministers conference in August 1989, the premiers of Newfoundland, Ontario and Quebec discussed the possibility of developing the remaining potential on the lower Churchill River. Potential generation of about 3600 MW could be shared among the three provinces.

A technical committee with representatives from Ontario Hydro, Hydro Quebec, and Newfoundland and Labrador Hydro has been appointed. This committee is currently discussing development plans for the generation and transmission associated with optimal distribution of the power to the three provinces. To deliver the power to load centres in Quebec and Ontario, at least a new 735 kV transmission line would be required to the Montreal area and a new direct current (DC) interconnection would be needed between Ontario and Quebec.

Since these early discussions are at an early stage, no firm conclusions can be made regarding amounts, timing and economic competitiveness. The Proposed Plan presented in Chapter 15 has sufficient flexibility to accommodate any agreement reached.

DESCRIPTION OF COMPONENTS OF FOSSIL AND NUCLEAR OPTIONS

As discussed in an earlier section, there are five major components that define an option. Figure 14–5 provides a summary of the major components of the 12 fossil and nuclear options, described in this section under the following five categories:

- Primary Energy/Fuel
- Conversion Process
- Environmental Control
- Configuration
- System Application

Primary Energy/Fuel

As shown in Figure 14–5, primary energy comprises coal, oil and natural gas for the fossil options, and uranium for the nuclear options.

Fuel is the dominant cost component of the life cycle cost of fossil options. Figure 14–6 shows forecast prices for coal, oil and natural gas.

Coal

Options 1, 2, 8, 9 and 10 all use US coal as their primary fuel. Option 3 uses low-sulphur Western Canadian coal.

There are large coal reserves in North America, including Western Canada, and in the Appalachian states directly south of Ontario. Although coal will continue to have other uses in industry, abundant reserves mean shortages are not forecast to occur.

There are considerable variations, however, in the make-up of coal. Some coals are high in sulphur content, others have only one-tenth as much.

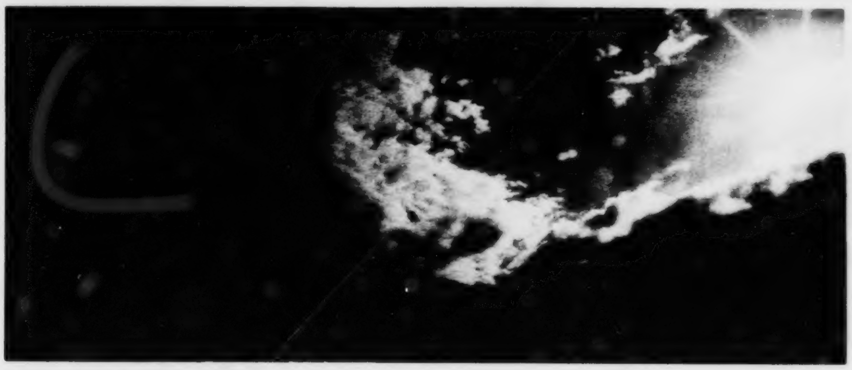
There are also variations in cost. Low-sulphur Western Canadian coal is more expensive than US coal, largely due to higher transportation costs. Cost is also affected by differences in the heat content of coal. Coal prices are expected to be stable in the long term.

Natural Gas

Options 5, 6, 7 and the first phase of Option 8, use mainly natural gas as their primary fuel.

Natural gas is supplied from the Western Canadian provinces. Natural gas is plentiful in the short term, but its long-term outlook is far less certain. It is a depletable resource with far less assured long-term reserves than coal. Future supplies of economic gas could become scarce.

Natural gas has many practical applications other than to fuel electricity generation. It is used in many heating applications and in the chemical industry as a chemical feed stock.



Energy from solar cells can contribute in communities dependent on expensive diesel generators.

Figure 14.5 Components of Fossil and Nuclear Options

Generation Type	Option Number	Primary Fuel	Conversion Process	Environmental Control*	Configuration	Principal System Application
Fossil	1	US Coal	CSC	FGD, SCR, ESP	4 x 800 MW	Base Load
	2	US Coal	CSC	FGD, SCR, ESP	4 x 500 MW	Intermediate
	3	WC Coal	CSC	SCR, ESP	4 x 500 MW	Intermediate
	4	LFO	CTU	**	2 x 150 MW	Peaking
	5	Gas/LFO	CTU	**	2 x 150 MW	Peaking
	6	Gas/LFO	CC	SCR**	2 x 660 MW	Intermediate
	7	Gas/LFO	CC	**	2 x 660 MW	Peaking
	8	Gas/LFO	CTU/CC phase	**	4 x 660 MW	Peaking
		US Coal	IGCC			Intermediate
	9	US Coal	IGCC	SCR**	4 x 660 MW	Base Load
	10	US Coal	AFBC	SCR, FF	4 x 200 MW	Base Load
Nuclear	11	Uranium	CANDU	Contained by design	4 x 881 MW	Base Load
	12	Uranium	CANDU	Contained by design	1 x 450 MW	Base Load

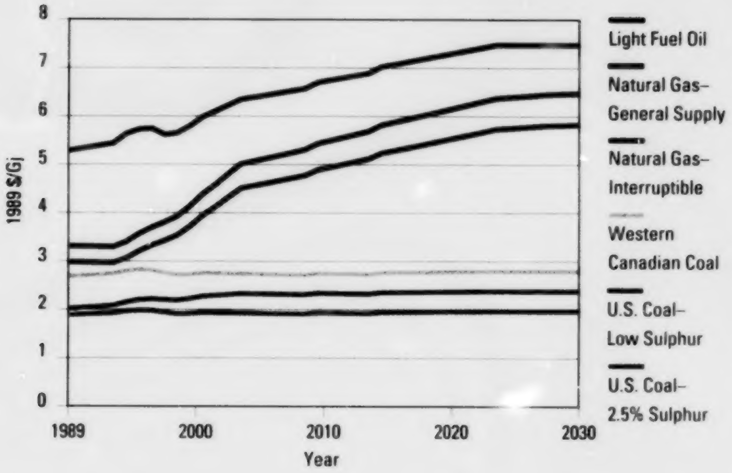
**Burners in all fossil options are design for low NOx emissions*

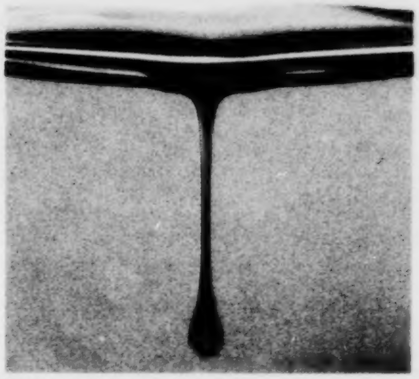
***Water/steam injection is used in all CTU/CC/IGCC options to reduce NOx emissions*

FGD = Flue Gas Desulpherzation
WC = Western Canadian
SUR = Selective Catalytic Reduction
LFO = Light Fuel oil
ESP = Electrostatic Precipitator
FF = Fabric Filter

Uranium costs less than fossil fuels.

Figure 14–6 **Forecast Prices For Coal, Oil And Natural Gas**





Oil is costlier fuel for electricity generation than coal and natural gas.

Forecast median prices (Figure 14–6) for natural gas supplied on a interruptible basis, is lower than for the general supply of natural gas. The interruptible contracts are most likely to be interrupted during the coldest winter period, when gas and electricity demands are at their peaks. To take year round advantage of the lower priced interruptible gas, the options which feature gas as the principal fuel use oil as a winter "backup".

Historically, gas prices have been volatile. While gas prices are expected to increase in real terms in the long term, and there is considerable price uncertainty due to the unpredictability of factors such as long-term global demand and costs of new gas reserves. In addition, capacity of natural gas pipelines is limited and any requirement for new lines could affect the price outlook.

Oil

Option 4 uses light fuel oil as its primary energy.

Oil is less abundant than natural gas, and is vulnerable to long-term shortages. Oil has great value as a transportation fuel and as feedstock for the chemical industry. Although not indigenous to Ontario in sufficient quantity, oil, like natural gas, is a western Canadian resource.

Presently, oil is costlier than coal and natural gas when used for electricity generation. Oil prices are expected to remain higher than gas in the future. Light fuel oil is the only grade acceptable for the generation options which Hydro plans to use. Oil from the Alberta Tar Sands is an abundant Canadian resource. However, the fuel prices for this resource will be much higher than the conventional oil price shown in Figure 14–6.

Uranium

Both Options 11 and 12 use uranium as their primary fuel.

There are abundant reserves of uranium in both Ontario and Saskatchewan. The cost of uranium is low compared to fossil fuels and, unlike fossil fuels, does not have significant competing uses. Figure 14–7 shows forecast prices for nuclear fuel. The prices rise early in the plan period, then remain relatively stable thereafter.

Conversion Processes

As shown in Figure 14–5, the conversion processes include conventional steam cycle (CSC), combustion turbine units (CTU), combined cycle (CC), integrated (coal) gasification combined cycle (IGCC), and atmospheric fluidized bed combustion (AFBC) for the 10 fossil options and CANDU for the two nuclear options.

Conventional Steam Cycle (CSC)

Figure 14–8 is a simplified block diagram of a typical CSC. In the conventional steam cycle, fuel in the form of coal, gas or oil is fed to a boiler. Combustion takes place in the boiler as air from fans is mixed with fuel in the burners. Heat energy is recovered within the boiler and converted to high pressure superheated steam.

The high pressure steam spins a turbine which drives a generator. The electrical energy produced by the generator is stepped up to a higher voltage for delivery to the Bulk Electricity System (BES).

Combustion Turbine Units (CTUs)

Figure 14–9 is a simplified block diagram of a typical CTU. CTUs may burn natural gas or oil. Fuel is usually fed directly to the combustion chamber along with high pressure

Figure 14–7 **Forecast Price Range for Incremental Supply of Nuclear Fuel**

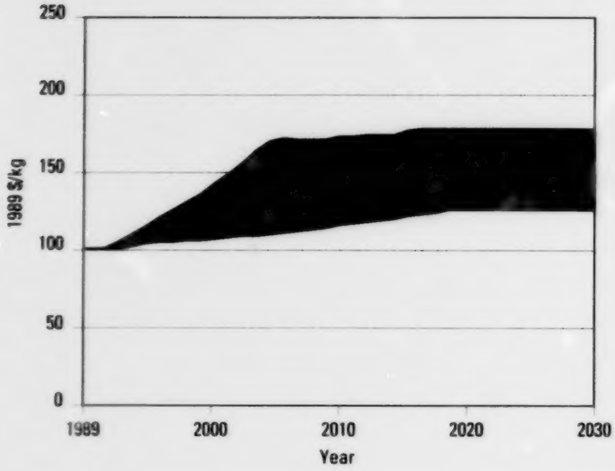


Figure 14–8 **Simplified Block Diagram of CSC and AFBC**

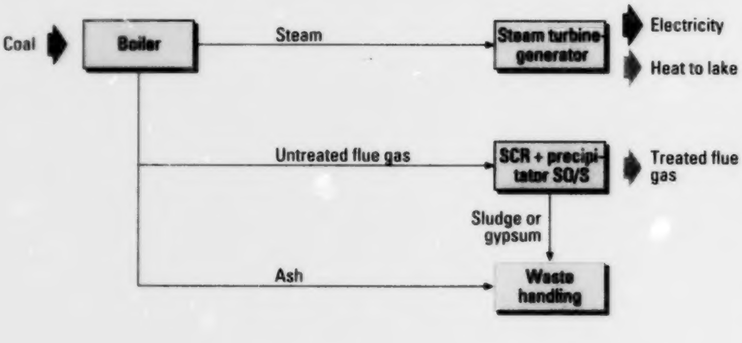


Figure 14–9 **Simplified Block Diagram of CTU**

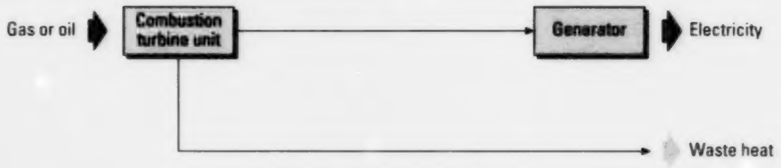
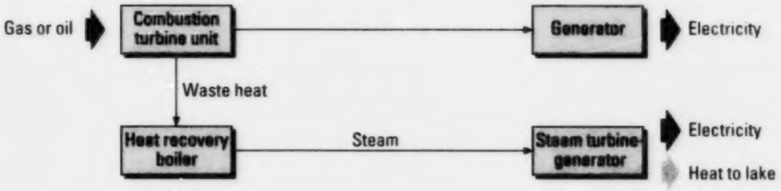

Gas or oil
Combustion turbine unit
Generator
Electricity
Waste heat

Figure 14–10 **Simplified Block Diagram of CC**


Gas or oil
Combustion turbine unit
Generator
Electricity
Waste heat
Heat recovery boiler
Steam
Steam turbine generator
Electricity
Heat to lake

air injected from a compressor. The fuel and air are burned, producing gases at temperatures between 900° and 1100° C.

The hot gases expand through the turbine blades causing the turbine to rotate at high speed. The turbine drives a conventional generator which generates electricity for delivery to the BES.

Combined Cycle (CC)

Combined Cycle units are made up of CTUs in combination with appropriately sized heat recovery steam generators (HRSG). Figure 14–10 is a simplified block diagram of a typical CC unit. As with CTUs, natural gas or oil is the primary fuel for CCs. The HRSG uses the heat of the exhaust gas from the CTUs to produce steam, which is used to drive a conventional steam turbine generator, producing electricity. By using exhaust gas to produce electricity, CC applications have higher efficiency than CTUs.

Integrated (Coal) Gasification Combined Cycle (IGCC)

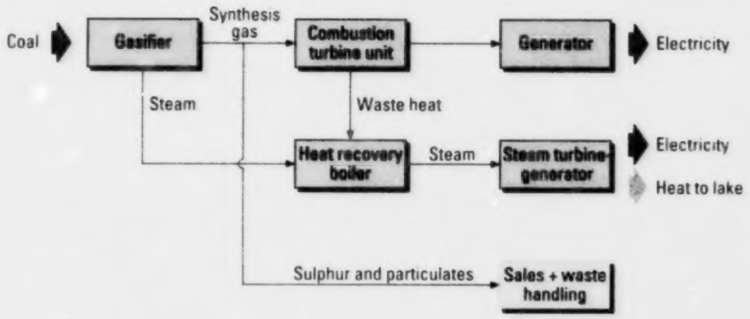
IGCC takes the CC conversion process one step further by adding a coal gasification plant to permit the use of lower cost coal as its primary fuel. The IGCC conversion process integrates several proven processes, such as combined cycle and coal gasification, into a single high efficiency, clean-fossil option. Figure 14–11 is a simplified block diagram of a typical IGCC plant.

The primary fuel, coal, is converted into synthesis gas in the gasifier. The synthesis gas is cooled and cleaned to remove particulates and sulphur before it is fed to the CTUs to produce electricity. IGCCs are not suitable for frequent start-ups and shutdowns.

An IGCC plant can be built as a phased or an unphased plant. A phased plant is built in three stand-alone stages. In the first phase, CTUs operate with natural gas or oil. In the second phase, a heat recovery steam generator and turbine generator is added to achieve higher capacity and efficiency. In the third phase, coal is converted to synthesis gas to accommodate higher loading or to offset high oil and gas prices. In general, phased plants provide short lead time flexibility to meet increasing demand.

Unphased plants are built in a single step, usually as fully integrated, high efficiency plants. Unphased plants are suitable for continuous operation over long intervals.

Figure 14–11 **Simplified Block Diagram of IGCC**

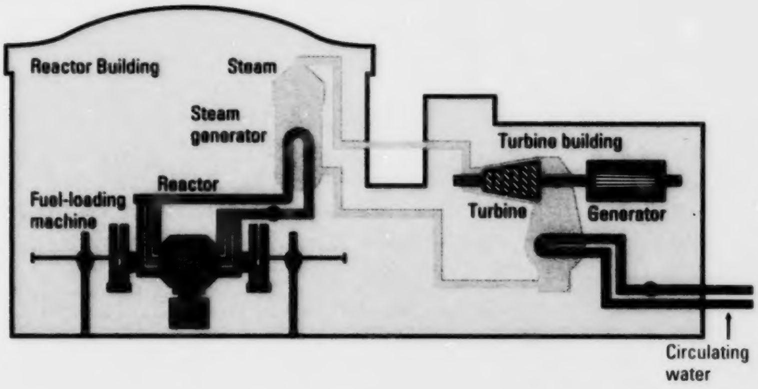

Coal
Gasifier
Synthesis gas
Combustion turbine unit
Generator
Electricity
Steam
Waste heat
Heat recovery boiler
Steam
Steam turbine-generator
Electricity
Heat to lake
Sulphur and particulates
Sales + waste handling

Atmospheric Fluidized Bed Combustion (AFBC)

AFBC units have the same basic components and functions as a conventional steam cycle plan, illustrated in Figure 14–8. The major difference lies in the use of a fluidized bed combustion boiler. Combustion heat from burning coal in the bed is used to produce superheated steam in tubes which pass through the boiler. Limestone is included in the bed to capture sulphur dioxide resulting from the combustion process.

Although this conversion process can use a variety of low grade fuels, the assumed primary fuel is US coal with 2.5% sulphur content.

Figure 14–12 **CANDU Unit**


Reactor Building
Steam
Steam generator
Reactor
Fuel-loading machine
Turbine building
Turbine
Generator
Circulating water

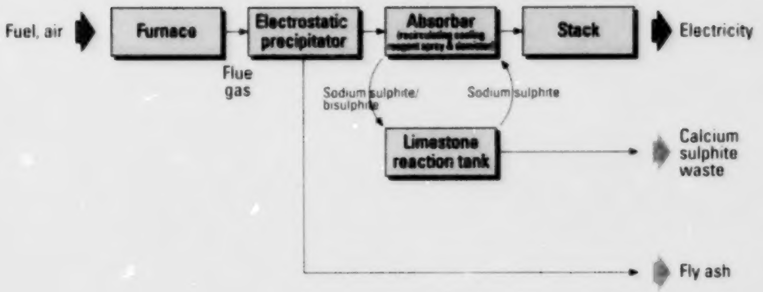
CANDU

A nuclear reactor is a facility which produces heat. The reactor and associated steam generator perform the same function as a boiler in a conventional steam cycle plant. The means of producing heat is the key difference between nuclear and fossil options. In the nuclear conversion process, heat is generated by a nuclear reaction. To sustain this reaction, the neutrons are slowed down or moderated.

CANDU, illustrated in Figure 14–12, is the conversion process used in Options 11 and 12. CANDU reactors, a unique technology, use deuterium oxide or heavy water as a moderator. By using heavy water† as a moderator†, CANDU units can use natural uranium as fuel. CANDU stands for CANada Deuterium Uranium.

Heavy water is also used to transport heat from the fuel bundles and provide heat to the steam generator. At the steam generator, steam is produced from ordinary water to drive a conventional turbine and generator which are separate from the reactor.

Figure 14–13 **Simplified Block Diagram of Limestone Dual Alkali FGD**



Environmental Control

Sulphur dioxide, nitrogen oxides, carbon dioxide and particulate emissions all have environmental impacts. They contribute to the formation of acid rain and global warming, known as the greenhouse effect. They can also affect local air quality.

Emissions from fossil options vary considerably, depending on what conversion processes and environmental control measures are used.

Although emissions from fossil options can never be zero, Hydro is confident that environmental effects associated with these options (other than CO_2 emissions) can be reduced with appropriate control measures. Local air quality and government acid gas regulations can be met by retrofitting environmental controls to existing stations and installing clean fossil options in the future.

The level of carbon dioxide (CO_2) emissions for each fossil option is a long-term concern. CO_2 is considered a major contributor to global warming – and there is no existing cost-effective technology which will reduce CO_2 emissions for any fossil option. Electrical efficiency improvements, along with non-fossil supply options, are preferable alternatives for CO_2 control.

To meet environmental standards, the following environmental controls are included in the consideration of fossil options:

- Flue gas desulphurization† (FGD) for reducing sulphur dioxide (SO_2) emissions;
- Selective Catalytic Reduction† (SCR), low NOX burners and water/steam injection for reducing nitrogen oxides emissions; and
- Electrostatic precipitators or fabric filters for removing particulates from flue gases.

Sulphur Dioxide Reduction

Fossil fuels such as coal, and to a lesser extent oil, contain a small percentage of sulphur that results in the formation of sulphur dioxide (SO_2) when burned. Most of the gas leaving the furnace of fossil-fueled options is carbon dioxide, nitrogen and water vapour, with sulphur dioxide making up about 0.17% by volume.

Traditionally, tall stacks have been used to disperse emissions and have successfully reduced local impacts of SO_2. However, the use of tall stacks has not solved the problem of long distance transport and disposition of pollutants, i.e., acid rain. Therefore, FGD equipment is needed to remove sulphur dioxide from flue gases.

FGD processes tend to be physically very large and expensive, since large volumes of flue gas must be treated. As sulphur dioxide is acidic, FGD processes use alkaline materials called reagents to absorb and remove the sulphur dioxide from the flue gas.

Basically, there are three main FGD processes which could be used: limestone slurry, limestone dual alkali, and lime spray dryer.

The limestone slurry process is widely used in the world today. Its the chosen option for Lambton, because it is a proven technology. While the limestone slurry process is used in some retrofits, the limestone dual alkali is selected for Options 1 and 2, because it has improved operability and higher removal efficiency than the limestone slurry process. It is also less costly, with 2.5% sulphur coal, than either the limestone slurry or lime spray dryer processes.

In the limestone dual alkali process, illustrated in Figure 14–13, flue gas leaving the furnace is first cleansed of fine ash by an electrostatic precipitator and then cooled by a spray of recirculating reagent in an absorber. A limestone reaction tank is used to regenerate the sodium sulphite/bisulphite reagent used in the absorber. Flue gas then passes through a demister and to the stack for dispersal. Calcium sulphite waste is produced in the process, which can be used as landfill or be treated to make wallboard. About 90% SO_2 removal efficiency is expected for this process.

In Options 3 and 4, the sulphur content of the fuel is low enough that an FGD plant is not required. In the IGCC and AFBC options, the removal of SO_2 is inherent in the conversion processes, as explained earlier. There are no SO_2 emissions in the natural gas-fueled options. These include Options 5, 6, 7 and the first two phases of Option 8.

Nitrogen Oxides Reduction

Oxides of nitrogen have long been recognized as causes of smog and ground level ozone. They are increasingly being recognized as contributors to low level ozone, as well.

Oxides of nitrogen are formed when fossil fuels such as coal, oil or natural gas are burned. Flue gases are mostly carbon dioxide, nitrogen and water, with NO_x making up 0.035% to 0.07% of the flue gas by volume. There are three basic approaches to controlling the emissions of nitrogen oxides: steam/water injection, low NO_x burners, and selective catalytic reduction. Another possible technology is urea injection. Hydro is currently testing this option.

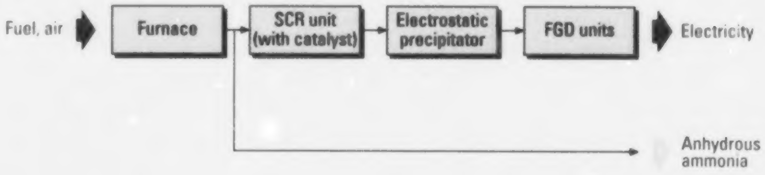
With steam/water injection, steam or water can be injected through the burners to limit flame temperature and to control the production of nitrogen oxides. Significant reductions in NO_x emissions can be achieved in oil or gas-fueled CTU's using this approach.

All the fossil options have burners designed to limit NO_x emissions.

Selective catalytic reduction, illustrated in Figure 14–14, is the only commercially available post-combustion nitrogen oxide control process. Options 1, 2, 3, 6, 9 and 10 all use this process to reduce NO_x emissions to Hydro standards. This is because of the higher loading (ACF) expected for these options.

In this process, anhydrous ammonia is introduced to the flue gas between the furnace and the electrostatic precipitator and the resulting mixture is passed through a catalyst bed of vanadium, platinum or titanium compounds. The ammonia reduces the nitrogen oxides to nitrogen and water in the presence of the catalyst. The used catalyst is the only waste

Figure 14–14 **Simplified Block Diagram of SCR**



that requires disposal. Up to 80% of NO_x emissions can be removed by this process. The catalyst is costly and must be replaced when it becomes non-reactive.

Particulate Reduction

Coal, and to a lesser extent oil, contains non-combustible material known as ash or particulates. Particulate emissions in flue gas are objectionable because they contribute to smog, respiratory problems and nuisance deposits in local communities. Coals burned by Hydro are cleaned at the mine to minimize ash levels to the extent possible. Hydro has also installed emission control devices between the furnace and the stack, which typically remove over 98% of the particulates. As with other emission controls, the devices tend to be large and expensive, because of the very large volumes of flue gas which have to be treated. The two basic types of particulate control devices are electrostatic precipitators and fabric filters. Electrostatic precipitators are used in all the coal-fueled CSC options.

An electrostatic precipitator is essentially a large box containing parallel rows of collecting plates and discharge electrodes through which the flue gases pass. A high voltage is applied to the electrodes and the ash particles become electrically charged and adhere to the collecting surfaces which are periodically cleaned. This method of particulate control is by far the most widely used on coal and oil-fueled utility boilers, and a forty year life-span is practical.

For the IGCC options, particulate control is inherent in the gasification process. For the AFBC option, particulate control is provided by fabric filters, which are relatively new for utility boiler applications. They have high removal efficiency.Their operating costs are higher than electrostatic precipitators, because bag filters would normally be replaced every three to five years. Overall, a 40-year life can be expected.

Radioactivity

In the CANDU option, radioactivity is controlled using the "ALARA" (as low as reasonably achievable) concept. Unlike fossil stations, the primary heat production process in the nuclear reactor is a "closed cycle". Under normal conditions, radioactivity remains within the uranium oxide fuel and the radioactivity is contained further in a zirconium alloy sealed sheath. The closed circuit heat transport system acts as an additional barrier and the whole reactor is contained within a containment building. Finally, the station is buffered by an exclusion area of one kilometre from the reactor core.

The possibility of accidents which can cause failure of these barriers and release of radioactivity is regarded as a public safety issue and is discussed in nuclear safety reports listed in the references to this report.

In summary, the concept of environmental control through containment involves minimal radioactive emissions in everyday operations.

Configuration

Options are developed around the best unit size for each conversion process. Optimum unit size is generally a function of economies of scale, unit sizes available, experience with particular unit size, system application intended and system need. Following are the selected unit sizes for the range of conversion processes:

- 500 MW and 800 MW CSC units
- 150 MW CTUs
- 660 MW CC and IGCC units
- 200 MW AFBC units
- 450 MW and 881 MW CANDU units

Another configuration consideration is the number of units per station, which also affects cost. Multi-unit stations, tend to have lower unit costs due to the sharing of common facilities and equipment, sharing of maintenance and administration staff, and standardization of procedures and training. Hydro's current standard is a four unit station configuration for large multi-unit stations that are used for intermediate and base load applications. The four unit standardized configuration is used in Options 1, 2, 3, 8, 9, 10 and 11.

For peaking applications and where small site restricts the number of units, fewer units per station are employed. Two units per station is the configuration used for options 4, 5, 6 and 7.

CANDU 3 (450 MW unit) is a new advanced CANDU concept developed by Atomic Energy of Canada Ltd. (AECL). A single unit concept is considered for prototype development and a multi-use station is considered for long-term potential.

The third configuration consideration is the arrangement of major components.

For optimal integration, the individual phases of CC and IGCC options must be appropriately configured. For options 6, 7, 8 and 9, the first phase of each 660 MW unit comprises three 150 MW CTUs and the second phase comprises one 210 MW heat recovery steam generator. For options 8 and 9, a third phase consisting of an appropriately sized gasifier is also required.

System Application

A conversion process in combination with a primary fuel is most suitable for a specific use. Some options are most effective when used a high percentage of the time. Others are best for shorter time periods. For example, options which have low capital costs and high operating costs are best only when needed for peak periods. Options with lower operating costs are best run a high percentage of time.

There are three broad categories of system application: peaking, intermediate and base load.

Options that are the most competitive at annual capacity factors (ACFs) of up to 20% are classified as peaking options. These include Options 4, 5, 7, and the first phase of Options 6 and 8.

Options that are most competitive between 20 and 60% ACF are classified as intermediate options. These include Options 2, 3, 6 and 8. Options 2, 3 and 8 could also be used for base load applications, but at higher cost than the options noted below.

Options that operate at greater than 60% ACF are classified as base load options. These include Options 1, 9, 10, 11 and 12.

These options can also be used at the higher intermediate loads, but at higher cost than intermediate options.

CHARACTERISTICS OF FOSSIL AND NUCLEAR OPTIONS

Earlier in this chapter, 10 fossil and 2 nuclear options are identified as potentially suitable for plan development. These 12 options all meet the basic primary criteria. However, there are major differences in characteristics, arising from the considerations discussed earlier, among the options. These characteristics are considered in the selection of options for plan development.

Figures 14-14 to 14-18 provide a summary of the major characteristics of the 12 options. Only major characteristics that show distinct

Figure 14-15 **Characteristics of Conventional Steam Cycle Options**

(Options 2 & 3 are similar to Option 1 except where noted)

Option 1 **4 x 800 MW US Coal with FGD & SCR**

System Application:	• Most suitable for base load
	• Intermediate load also possible
Cost:	• The lowest cost fossil-fueled option at high ACF
	• LUEC (1989$): 3.9 ¢/kWh at 80% ACF 4.5 ¢/kWh at 60% ACF
	• Fuel is a dominant cost component of the life cycle cost, but fuel prices are expected to remain low to moderate for the foreseeable future
Environmental:	• With appropriate environmental control equipment, current environmental regulations and Hydro standards can be met
	• SO_2 emissions can be mitigated to 1.6 g/kWh with the use of FGDs
	• NO_x emissions can be mitigated to 0.25 g/kWh with the use of SCRs
	• CO_2 emissions are 860 g/kWh and cannot be effectively mitigated
	• Solid wastes are 96 g/kWh, but most scrubber and ash wastes are suitable for reuse in making secondary products such as wallboard and cement
Socio-Economics:	• Significant direct and indirect Ontario employment associated with the capital and OM&A components
	• US coal must be imported; hence, few Canadian or Ontario jobs created due to fuel purchases
	• About 45% of life cycle cost is spent in Ontario at 80% ACF
Safety:	• Existing similar plants have good safety records
Flexibility:	• Large units have less operational flexibility
	• Construction lead time of 5 – 8 years
	• Some flexibility to burn lower sulphur coal
Resource Preference:	• Fuel is non-renewable, but plentiful resource
	• Fuel is non-indigenous to Canada
Technical Soundness:	• Ontario Hydro has extensive experience with the conventional steam cycle
	• Hydro has no direct experience with the 800 MW unit size, but there is extensive world experience
	• No Hydro experience with FGD, but there is extensive experience worldwide and good performance demonstrated in the US
	• Experience with SCR is limited to Germany and Japan

Option 2 4 x 500 MW US Coal with FGD & SCR	**Option 3** 4 x 500 MW Western Canadian Coal with SCR
• Suitable for intermediate and base loads • Peaking also possible • LUEC: 5.0 ¢/kWh at 60% ACF 6.3 ¢/kWh at 40% ACF 10.2 ¢/kWh at 20% ACF	• Suitable for intermediate and base loads • Peaking also possible • LUEC: 5.1 ¢/kWh at 60% ACF 6.2 ¢/kWh at 40% ACF 9.4 ¢/kWh at 20% ACF • Fuel prices not affected by fluctuating exchange rates • Large portion of fuel cost is transportation • SO_2 emissions are 2.3 g/kWh because of low sulphur content of coal • CO_2 emissions are 910 g/kWh • Solid wastes are 48 g/kWh and consist mainly of ash
• About 60% of life cycle cost is spent in Ontario at 40% ACF	• Employment and regional development benefits mainly in western provinces • About 55% of life cycle cost is spent in Ontario at 40% ACF
• Operational flexibility for peaking, intermediate and base load applications	• Operational flexibility for peaking, intermediate and base load applications • Fuel is indigenous to Canada but not Ontario
• Hydro has extensive direct experience with the 500 MW unit size with 12 units in-service	• Hydro has extensive direct experience with the 500 MW unit size with 12 units in-service • Hydro has experience with western Canadian coal blended with US coal in eight 500 MW units • Hydro has no experience with the larger boilers required for 500 MW units burning western Canadian coal (not blended)

Figure 14-16 **Characteristics of Combustion Turbine Unit Options**

(Option 5 similar to Option 4 except where noted)

	Option 4 2 x 150 MW Oil-fueled	**Option 5** 2 x 150 MW Natural Gas-fueled
System Application:	• Most suitable for peaking • Intermediate and base loads possible but costly	
Cost:	• Light fuel oil is the most expensive fossil fuel • Although fueling cost is high, the low capital cost makes the CTU option cost effective at low ACF operation • LUEC (1989$): 10.4 ¢/kWh at 20% ACF, 12.8 ¢/kWh at 10% ACF • Fuel prices are highly uncertain and are expected to increase in the long term	• LUEC: 8.5 ¢/kWh at 20% ACF, 10.7 ¢/kWh at 10% ACF • Gas prices are forecast to have long term real increases but to remain lower than oil
Environmental:	• Current environmental regulations and Hydro standards can be met • Peaking application reduces potential environmental impacts • Light fuel oil is low in sulphur content and SO_2 emissions are similar to scrubbed US coal at 1.6 g/kWh • NO_x emissions are about 0.9 g/kWh based on current technology, but are expected to be lower with advances in CTU design • CO_2 emissions comparable to US coal at 860 g/kWh • No solid wastes	• No SO_2 emissions • At 605 g/kWh CO_2 emissions are low relative to other fossil fuel options
Socio-Economics:	• Limited employment benefits in Ontario due to use of imported fuel which is the dominant component of life cycle costs • About 30% of life cycle cost is spent in Ontario at 10% ACF • Potential for expansion of manufacturing base of CTUs in Ontario	• At 10% ACF about 30% of life cycle cost is spent in Ontario
Safety:	• Existing similar plants (of smaller sized units) have good safety records	
Flexibility:	• Construction lead time of 1 – 2 years provides planning flexibility to meet higher than expected load growth • Manufacturing capability may be a constraint • Fuel oil can be stored • Operational flexibility, especially for peaking	• To utilize interruptible gas (lower price) requires stored oil fuel as a backup
Resource Preference:	• Long-term supply uncertainty • High value in alternative applications • Fuel is non-renewable but indigenous to Canada	
Technical Soundness:	• Although CTUs of the size proposed are still in development state, the option is based on proven design with many years of world experience • Should this size prove impractical, Hydro has the option to install more units of smaller sizes	

Figure 14-17 Characteristic of Combined Cycle Options

[illegible]

	Option 6 2 x 660 MW Natural Gas – Fueled With SCR-Intermediate	**Option 7** 2 x 660 MW Natural Gas-Fueled-Peaking
System Application:	• To meet intermediate load, but also suitable for peaking • Base load possible but costly	• To meet peaking, but also suitable for intermediate load
Cost:	• LUEC (1989$): 6.0 ¢/kWh at 60% ACF 6.9 ¢/kWh at 40% ACF • Higher efficiency makes it more cost effective than CTUs at ACFs higher than about 20%	• LUEC: 8.6 ¢/kWh at 20% ACF 13.1 ¢/kWh at 10% ACF • Due to higher efficiency, this option may become lowest cost peaking option, if natural gas prices increase more than forecast
Environment:	• Current environmental regulations and Hydro standards can be met • No SO_2 emissions • NO_x emissions can be mitigated to 0.25 g/kWh with the use of SCRs • At 430 g/kWh, CO_2 emissions are among the lowest fossil options • No solid wastes	• At 425 g/kWh, CO_2 emissions are the lowest amongst fossil options
Socio-Economics:	• Limited employment benefits in Ontario, due to use of imported fuel, which is dominant component of life cycle costs • At 40% ACF about 35 – 60% of life cycle cost is spent in Ontario • Modular or staged development may reduce local community impacts • Potential for expansion of manufacturing base of CTUs in Ontario	• At 10% ACF about 45 – 65% of life cycle cost is spent in Ontario
Safety:	• Existing similar plants elsewhere have good safety records	
Flexibility:	• Short construction lead times of 3 – 5 years and potential for phased development provide planning flexibility • To utilize interruptible gas (lower price) requires stored oil fuel as a backup • Operational flexibility over a wide range of system applications	
Resource Preference:	• Long-term supply uncertainty • High value in alternative applications • Fuel is non-renewable but indigenous to Canada	
Technical Soundness:	• Although Hydro has no direct experience with CCs, the option has proven worldwide experience • Characteristics of CTUs that make-up CCs are the same as for Options 4 and 5	

Figure 14–18 **Characteristic of IGCC and AFBC Options**

(Option 9 and 10 similar to Option 8 except where noted)

Option 8 **4 x 660 MW US Coal – Fueled Phased IGCC**

System Application:	• Phased construction makes the option suitable for the whole range of applications
Cost:	• Phased IGCC offers cost advantages by matching the development of individual phases to the system requirements • LUEC (1989$): 11.6 ¢/kWh for CTU phase at 10% ACF 7.2 ¢/kWh for CC phase and operation at 30% ACF 6.0 ¢/kWh for IGCC phase and operation at 45% ACF
Environmental:	• Current environmental regulations and Hydro standards can be met • For the first phase, emissions are similar to the CTUs of Option 5, and for the second phase they are similar to the CCs of Option 7 • Emissions for the IGCC phase are: SO_2 – 0.52 g/kWh NO_x – 0.3 to 0.5 g/kWh CO_2 – 905 g/kWh • Dry solid wastes for IGCC phase, which can be easily managed, are 31 g/kWh, putting it among the lowest coal options
Socio-Economics:	• Significant direct and indirect Ontario employment associated with the capital and OM&A components • Fuel must be imported; hence few Canadian or Ontario jobs created due to fuel purchases • At 40% ACF about 50 – 60% of life cycle cost is spent in Ontario
Safety:	• No safety risk is expected
Flexibility:	• Phased IGCC offers good planning flexibility, development of the option in phases results in short lead time and ability to match generation to system requirements • Phase I offers CTU economy for peaking needs • Phase II offers the ability to handle increased loads/higher gas prices • Phase III gives the ability to produce synthesis gas from lower cost coal, thus providing flexibility of fuel switching and economy at higher ACF operations
Resource Preference:	• Phase I and II use natural gas as their main fuel and have resource preference similar to Option 5 • Phase III uses US coal as its main fuel and has resource preference similar to Options 1 and 2
Technical Soundness:	• Ontario Hydro has no direct experience with this technology • Commercial applications worldwide are limited to demonstration units of 100 MW size • Although the component phases are well known, long-term performance of the concept has not been demonstrated

Option 9 4 x 660 MW US Coal-Fueled Unphased IGCC with SCR	**Option 10** 4 x 200 MW US Coal-Fueled AFBC with SCR
• Most suitable for base load, but intermediate load also possible • LUEC: 4.2 ¢/kWh at 80% ACF 4.8 ¢/kWh at 60% ACF	• Most suitable for base load, but intermediate load also possible • LUEC: 5.2 ¢/kWh at 80% ACF 6.1 ¢/kWh at 60% ACF
• At 0.47 g/kWh, SO_2 emissions are the lowest amongst the coal options • NO_x emissions can be mitigated to 0.25 g/kWh with the use of SCRs • CO_2 emissions are 805 g/kWh • Dry solid wastes, which can be easily managed, are 28 g/kWh, making it the lowest of the coal options	• SO_2 emissions are comparable to scrubbed US coal at 1.7 g/kWh • NO_x emissions can be mitigated to 0.25 g/kWh with the use of SCRs • CO_2 emissions are 920 g/kWh • Solid wastes are 82 g/kWh
• At 80% ACF about 50 – 60% of life cycle cost is spent in Ontario	• At 80% ACF about 50 – 60% of life cycle cost is spent in Ontario
• Lacks the planning flexibility associated with phased construction	• Can be designed to use a number of low-grade fuels • Lacks the planning flexibility associated with phased construction
• Similar to Phase III of Option 8	• Similar to Phase III of Option 8
	• Ontario Hydro has no experience with this concept • Some world experience, but limited to small size • Long term performance has not been demonstrated, especially for base load applications

Figure 14-19 **Characteristics of Candu Options**

(Option 12 similar to Option 11 except where noted)

Option 11 4 x 881 MW CANDU

System Application:
- Most suitable for base load application
- Suitable for intermediate load (40 to 60%)

Cost:
- Although capital cost is high, the relatively low operating costs make this option the lowest cost option for base load applications
- LUEC (1989$): 3.1 ¢/kWh at 80% ACF
  4.0 ¢/kWh at 60% ACF

Environmental:
- Current environmental regulations and Hydro standards can be met
- The CANDU system is a closed system which under normal operation has virtually no emissions; historically releases have been less than 1% of AECB approved levels
- Principal by-products include low volume but long-lived high and low-level radioactive waste
- A method for the long-term disposal of used fuel is undergoing a public review by the federal Environmental Assessment Review Panel

Socio-Economics:
- Significant direct and indirect Ontario employment benefits
- At 80% ACF over 85% of life cycle cost is spent in Ontario
- Community impacts moderate for existing sites, potentially significant for new sites
- Utilize and possibly expand the existing infrastructure in the Ontario nuclear industry
- The public is concerned that there is a risk of radioactive release

Safety:
- Excellent safety record
- Design meets all AECB requirements
- Public safety concerns have been extensively reviewed, most recently by Dr. F.K. Hare in the Ontario Nuclear Safety Review. It was found that Ontario Hydro reactors are being operated safely and at high standards of technical performance

Flexibility:
- Operational flexibility limited until cycling capability is well-established
- Construction lead times of about 5–8 years restricts planning flexibility

Resource Preference:
- Uranium is indigenous to both Ontario and Saskatchewan
- Non-renewable but plentiful and concentrated resource
- Fuel has few alternative uses

Technical Soundness:
- Well-established and proven technology with many years of Ontario Hydro experience
- Demonstrated benefits from a standardized nuclear program

[illegible]

Option 12 **1 x 450 MW CANDU**

- **At 80% ACF LUEC is estimated to be above 4 ¢/kWh**

- **Community impacts moderate, due to small size**

- **Is expected to have similar safety characteristics as the more established 881 MW CANDUs**

- **Estimated construction lead times of 3 to 5 years provide more planning flexibility**

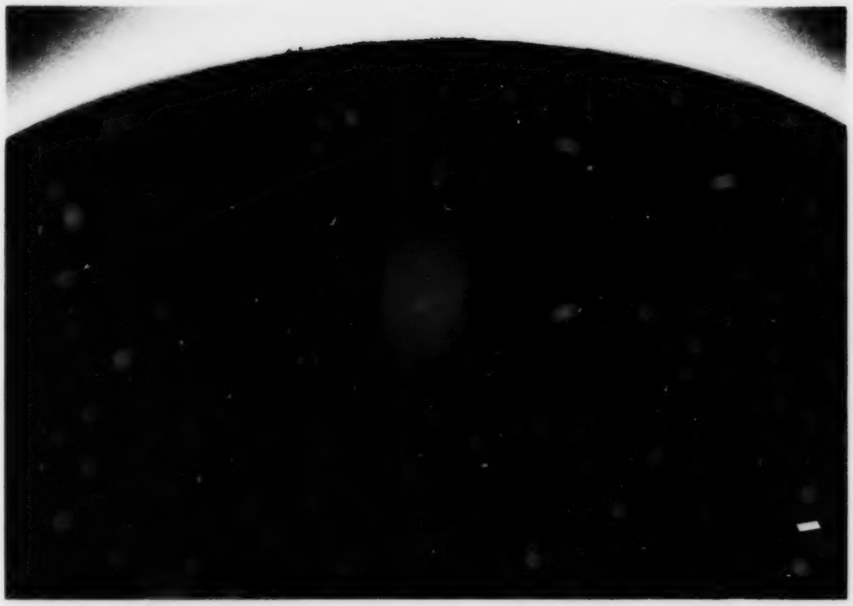
- **Requires prototype to demonstrate commercial viability** differences among the options are outlined to highlight the dominant characteristics that entered the selection process. More details on the characteristics of these options are contained in the background documents for the Demand/Supply Plan. All estimates shown in these Figures are for installation of the options on an existing site.

Figure 14–20 shows the environmental performance for the 10 fossil options. Figure 14–21 shows the LUEC estimates for the 10 fossil and 2 nuclear options for a range of Annual Capacity Factors, again assuming installation on an existing site.

RATIONALE FOR SELECTION OF OPTIONS FOR PLAN DEVELOPMENT

Earlier in this chapter, 14 major supply options were identified as being potentially suitable for plan development. The two purchase options were described and the reasons why the Quebec offer was turned down, and agreement reached with Manitoba, were explained. This section evaluates the remaining fossil and nuclear options and selects the six options used in plan development (Chapter 15).

The ten fossil (coal, oil, gas) options were extensively analyzed in the Thermal Cost Review. The 4x881 MW CANDU option was extensively reviewed in the Ontario Nuclear Cost Inquiry. The 1x450 MW CANDU 3 option is an innovative, new CANDU concept that has undergone research and study by AECL.



The construction of major transmission lines is a key component of purchases from neighbouring utilities.

[illegible] 14.20 Environmental Performance of Fossil Options

Option Number	Description	SO2 (g/k Wh)	NOx (g/k Wh)	CO2 (g/k Wh)	Solid Wastes (g/k Wh)
1	4 x 800 MW US Coal CSC/FGD/SCR	1.6	0.25–0.31	860	95
2	4 x 500 MW US Coal CSC/FGD/SCR	1.6	0.25–0.31	860	95
3	4 x 500 MW WC Coal CSC/SCR	2.3	0.25–0.31	910	48
4	2 x 150 MW Oil CTU	1.6	0.88	860	0
5	2 x 150 MW Gas CTU	0	0.87	605	0
6	2 x 660 MW CC/SCR – Intermediate	0	0.25–0.31	430	0
7	2 x 660 MW CC – Peaking	0	0.62	425	0
8	4 x 600 MW Phased IGCC*	0.52	0.30–0.53	905	31
9	4 x 660 MW Unphased IGCC/SCR	0.47	0.25–0.31	805	28
10	4 x 200 MW AFBC/SCR	1.7	0.25–0.31	920	82

**Data shown are for IGCC phase, CTU and CC phasees are similar to Option 5 and 7, respectively*

Figure 14.21 LUEC Summary for FOSSIL and Nuclear Options

Option Number	Description	LUEC in 1989 cents/kWh 10%ACF	20%ACF	40%ACF	60%ACF	80%ACF
1	4 x 800 MW US Coal CSC/FGD/SCR	15.6	9.0	5.6	4.5	3.9
2	4 x 500 MW US Coal CSC/FGD/SCR	18.0	10.2	6.3	5.0	4.3
3	4 x 500 MW WC Coal CSC/SCR	15.8	9.4	6.2	5.1	4.5
4	2 x 150 MW Oil CTU	12.8	10.4	9.1	8.6	8.5
5	2 x 150 MW Gas CTU	10.7	8.5	7.2	6.8	6.6
6	2 x 660 MW CC/SCR – Intermediate	13.9	9.2	6.9	6.0	5.5
7	2 x 660 MW CC – Peaking	13.1	8.6	6.5	5.6	5.2
8	4 x 660 MW Phased IGCC	N/A	N/A	6.0	N/A	N/A
9	4 x 660 MW Unhased IGCC/SCR	18.5	10.4	6.2	4.8	4.2
10	4 x 200 MW AFBC/SCR	24.7	13.6	8.0	6.1	5.2
11	4 x 881 MW CANDU	22.0	11.2	5.8	4.0	3.1
12	1 x 450 MW CANDU	N/A	N/A	N/A	N/A	>4*

***Notes:** LUEC estimates are calculated based on Existing Site and assumed in–service date of October 2002.*
**LUEC for the CANDU 3 option is estimated to be greater than 4 cents/kWh at 80% ACF based on preliminary data*

The main characteristics of these 12 options are described in the previous section against the evaluation criteria discussed earlier. These characteristics will play an important role in the selection ofoptions for plan development.

It is also important to select options from different conversion processes that best meet the evaluation criteria. Carrying forward a number of distinctively different options enables the formulation and evaluation of plans with significantly different characteristics.

The selection of options must also consider the requirements of the Bulk Electricity System. As explained in Chapter 3, system requirements consist of base, intermediate and peaking loads. However, no single generation option has all the characteristics that best meet needs over the entire base load to peaking range. Therefore, it is necessary to select a mix of options.

Options Selected to Meet Base Load Requirements

Future requirements for new major supply in the 25-year planning horizon total 15 GW of capacity and 61 TWh of energy in the median forecast. The existing base load plants will not be sufficient to supply the increase in base load requirements. Therefore, plans will require options which can provide a substantial amount of base load capacity.

The options considered suitable for plan development (base load) are:

- Option 1 – 4 x 800 MW US coal-fueled CSC equipped with FGD and SCR
- Option 9 – 4 x 660 MW IGCC (unphased) equipped with SCR; and
- Option 11 – 4 x 881 MW CANDU

Three of the six conversion processes – CTU, CC and AFBC – are not suitable, because of their high fueling costs. In the unlikely

However, no single generation option available has all the characteristics that best meet the needs over the entire base load to peaking range.

event of large reductions in gas prices (current and forecast), gas-fueled, base loaded Combined Cycle stations could become economic. Such a station in place of one CANDU station would consume gas equivalent to 25% of the total 1988 Ontario consumption.

CSC for Base Load Requirements

Rationale for Selecting Option 1 – 4x800 MW CSC

This option is selected as the fossil base load alternative for plan analysis. As shown in Figure 14–20, this option is the lowest cost (3.9 ¢/kWh at 80% ACF) fossil option for base load applications. Although this option has high initial capital cost, it is slightly lower than the nuclear options. Unlike nuclear, fuel is a dominant cost component of the option's life cycle cost, hence its economics are very sensitive to changes in long-term coal prices. However, coal prices are expected to remain stable in the long term.

This option is equipped with appropriate environmental control equipment to meet all current environmental regulations and Hydro standards. This equipment includes FGDs, which would remove over 90% of SO_2; SCRs, which would remove up to 80% of NO_x; and precipitators, which would remove over 98% of particulates in the flue gas.

Although the fuel used is non-indigenous to Ontario and a non-renewable resource, it is a plentiful resource with proven reserves of hundreds of years at current production levels.

Ontario Hydro has extensive experience with the CSC concept. Although Hydro has no direct experience with the 800 MW unit size, there is extensive world experience.

Rationale for Not Selecting Option 2 or 3 – 4x500 MW CSC

Option 1 is selected as the best option amongst the CSCs for base load applications. Its characteristics are sufficiently similar to those of Options 2 and 3 to be considered representative of the CSCs for the purpose of plan analysis.

As shown in Figure 14–21, the smaller CSC option has higher costs than Option 1 for base load applications.

Option 2 is simply a smaller version of Option 1. There is some operational flexibility advantages for lower ACF operation associated with smaller unit size. However, since there is little difference at higher ACF operation, Option 2 is not selected for base load applications.

In Option 3, the use of lower sulphur western Canadian coal results in sulphur dioxide emissions similar to those for Option 1. Because scrubbers are not required, the solid wastes for Option 3 are half that of Option 1. However, its CO_2 emissions are slightly higher than Option 1. The differences in environmental and resource preference characteristics do not offset the higher cost for Option 3. Hence, Option 3 is not selected.

IGCC and AFBC for Base Load Requirements

Rationale for Selecting Option 9 – Unphased IGCC

The 4x660 MW unphased IGCC is selected to provide a representative from among the developing fossil options for the purpose of plan development and analysis. Although marginally higher in cost than Option 1 for base load applications, Option 9 promises improved environmental performance and efficiency.

Hydro has no direct experience with the IGCC concept. Commercial applications worldwide are limited to demonstration units of 100 MW size. Although the components of the IGCC concept are well understood, long-term performance has not been demonstrated on a large scale for base load applications. As a promising high-efficiency, clean-fossil option, it is appropriate for consideration in plan development. However, there are some concerns about its undemonstrated performance that would restrict it to implementation later in the planning period to allow sufficient time for Hydro to gain confidence in the concept.

Rationale for Not Selecting Option 8 – Phased IGCC or Option 10 – AFBC

Option 8 is similar to Option 9 except the gasifier portion of the plant is of a different design that is lower in cost but also lower in efficiency, and is an optimal design for lower Annual Capacity Factor operations. Although

All nuclear reactors used by Ontario Hydro are CANDU types.

Option 8 provides planning flexibility due to phased construction, it is more suitable for intermediate or peaking applications due mainly to its gasifier design.

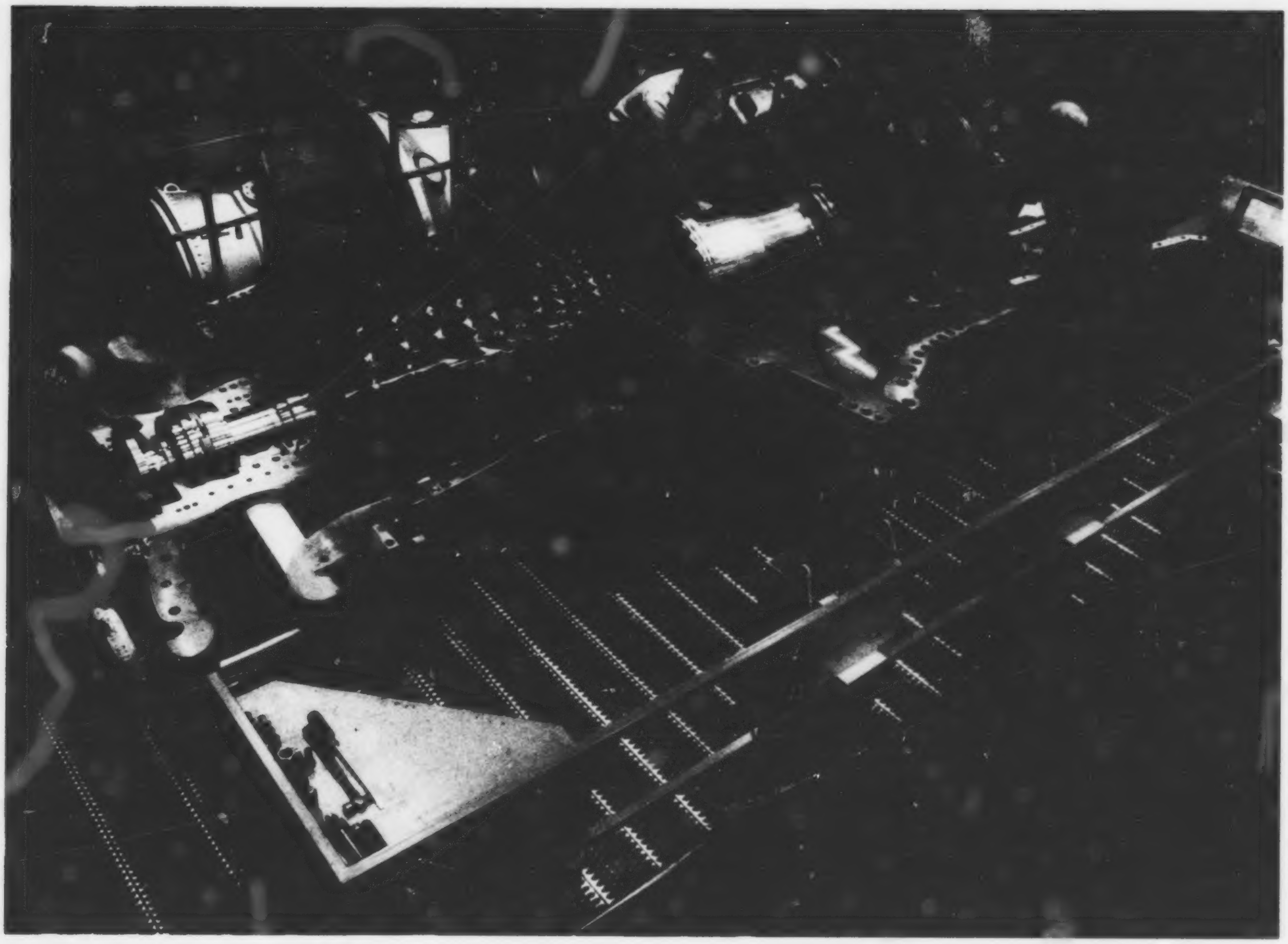
As shown in Figure 14–21, the LUEC for the AFBC option is over 20% higher than the LUEC for the IGCC option for base load applications. Although a developing clean coal option, AFBC has poorer environmental performance characteristics than IGCC. It has slightly higher CO_2 emissions, but significantly higher SO_2 emissions and solid wastes than the IGCC. Its only advantage is that it can be designed to use a number of low grade fuels. As with the IGCC, Hydro has no experience with AFBC and there is limited world experience. Long-term performance of the option has not been demonstrated, especially for base load applications. Accordingly, Option 10 is not selected for plan analysis. The IGCC option appears better suited for base load applications among the developing fossil options.

CANDU for Base Load Requirements

Rationale for Selecting Option 11 – 4x881 MW CANDU

As illustrated in Figure 14–21, the 4x881 MW CANDU is the lowest cost (3.1 cents/kWh at 80% ACF) option for base load applications. Despite high capital costs, its low fueling costs contribute to making it an option that has low life cycle costs and very stable, inflation resistant, annual energy costs.

The CANDU meets all current environmental regulations and Hydro standards, and would assist in meeting anticipated CO_2 regulations. A method for the long-term disposal of used fuel is undergoing a public review by the federal Environmental Assessment Review Panel. Public safety concerns have been exten-



Combustion turbine units are suitable for meeting peak power demands.

sively reviewed, most recently by Dr. F.K. Hare in the Ontario Nuclear Safety Review. It was found that Ontario Hydro reactors are being operated safely and at high standards of technical performance. Dr. Hare also determined that the risk of accidents serious enough to affect the public adversely can never be zero, but is very remote.

The CANDU is fueled with uranium that is indigenous to both Ontario and Saskatchewan. Although uranium is a non-renewable resource, it is a plentiful resource with few alternative uses.

The 4 x 881 MW CANDU is based on a well-established and proven technology with many years of successful Hydro experience. Continuation of the standardized nuclear program would result in long-term benefits including lower costs, and continuity of work for major component suppliers.

Rationale for Not Selecting Option 12 – CANDU 3

The CANDU 3 is an advanced CANDU concept developed by Atomic Energy of Canada Limited during the past few years. This concept promises cost reductions and improvements in the lifetime capability factor of the nuclear reactor through changes such as the improved maintainability and constructability of the reactor. It features a 450 MW unit, as compared with the 4x881 MW standard units used in Hydro's 4x881 MW stations. AECL judges these smaller units to be economically advantageous for Canadian and overseas applications.

Hydro's assessment of the CANDU 3 concept concludes:

- Since no CANDU 3 has been built and proven, Ontario Hydro cannot consider it for a large scale commercial program of electric supply at this time; and
- Even assuming a CANDU 3 is built and performs reliably, it does not promise economic improvement over the economies of scale already provided by the proven standardized 4x881 MW stations utilized by Ontario Hydro.

Because of these two considerations, the CANDU 3 is not proposed as a current option for large scale development. However, recognizing the interest in a smaller size alternative for both Canadian and overseas applications, Hydro has indicated that it is willing to consider purchasing electricity from a CANDU 3 unit at avoided costs.

Options Selected to Meet Peak Load Requirements

Even with the implementation of load shifting programs and the development of the remaining economic hydroelectric sites in Ontario, there will still be a need for additional peaking options.

For peaking application, four of the six conversion processes – CSC, unphased IGCC, AFBC and CANDU – are unsuitable because of the high LUEC for low capacity factor operation. The three options retained for plan development (peak load) are the CTU, CC Phase 1 and Phased IGCC – Phase 1.

CTU for Peaking Load Requirements

Rationale for Selecting Option 5 – Gas CTU

As illustrated in Figure 14–21, the gas-fueled CTU is the lowest cost option for peaking applications at 10% ACF. It is an environmentally clean option with no SO_2 emissions and no solid wastes. NO_x emissions are within Hydro standards and are expected to be lower in the future as advances are made in CTU design. CO_2 emissions are about 30% lower than those of coal and oil-fueled options.

Construction of CTUs at existing fossil facilities is the shortest lead time major supply option available, providing planning flexibility to meet higher than expected load growth. These operating stations provide short lead time by having trained operating and maintenance staff available and by making best use of existing transmission, land and other station service facilities. Another flexibility feature is its ability to use light fuel oil as an alternate fuel. By providing oil backup, Hydro can take advantage of lower price interruptible contracts for natural gas.

Natural gas, with alternative uses in heating and in the chemical industry, faces potential long-term shortages in supply as a fuel for electricity generation. Natural gas prices are highly uncertain and are expected to increase in the long term. However, addition of the CC phase, to improve efficiency; and the gasification phase, to permit a switch to lower cost coal, can offset potentially high gas prices in the future.

Although the 150 MW CTU size proposed for this option is still in a development state, the design is based on a proven conversion process with many years of world experience. If this CTU size were proven impractical, Hydro has the option to install more units of a smaller size.

Rationale for Not Selecting Option 4 – Oil CTU

Option 4 is similar to Option 5 except its primary fuel is light fuel oil. Because oil prices are expected to remain higher than natural gas, this option has costs that are higher than Option 5 for all applications. This option has no inherent advantages over Option 5 except its ability to store fuel in large quantities. However, this very small advantage does not offset its poorer environmental performance and higher costs.

CC and IGCC for Peaking Load Requirements

As illustrated in Figure 14–21, the CCs and IGCCs all have LUECs that are higher than Option 5 for low ACF operations. However, as the ACF goes above 20%, the CCs become more economic, and as the ACF goes above 40%, the IGCCs have the economic advantage.

Although CCs and IGCCs are not specifically selected for peaking, the selection of CTUs provides the flexibility to undergo these conversion processes, when warranted by increasing demand or fuel prices. Hence, the first phase

Plans address the need to link stations to the existing transmission grid.

of CC and IGCC can be considered suitable for peaking applications.

Options Selected to Meet Intermediate Load Requirements

Studies have shown that future requirements consist mainly of base and peaking loads. The intermediate load requirements are expected to be mostly met with existing coal-fueled stations. It is only later in the 25-year planning horizon that additional intermediate capacity may be required.

As illustrated in Figure 14–21, options that are cost competitive for base load applications are also competitive at the high-intermediate load range. Hence, selected options for base load applications may also be suitable for high-intermediate load applications.

Options that are cost competitive for peaking applications are also competitive at the low-intermediate load range. Hence, selected options for peaking load reqirements may also be suitable for low-intermediate load requirements.

Therefore, the selection of options for intermediate load applications does not have to re-evaluate options that are ideally suitable for applications within narrow bands of the base and peaking ranges. These include the CANDU and CTU options.

The two additional options not previously selected for peaking and base load application are:

- Option 6 – 2 x 660 MW CC equipped with SCR; and
- Option 8 – 4 x 660 MW Phased IGCC – phase 2

CSC for Intermediate Load Requirements

Rationale for Not Selecting Any CSC Options

As explained earlier in the selection of base load options, Option 1 is the best CSC for base load applications. This also applies for the high-intermediate range of applications. Hence, no new option has to be selected to represent the CSC for this purpose.

Since there are technical limitations to the cycling capabilities of the large CSC units, the smaller CSC units may be more appropriate at the low-intermediate range of applications. However, CTU/CCs are more cost effective and have better environmental and flexibility characteristics for this range of applications. Therefore, a representative option from the CSC is not necessary for the limited application for which it might be suitable.

CC , IGCC and AFBC for Intermediate Load Requirements

Rationale for Selecting Option 6 – CC and Option 8 – Phased IGCC

Options 6 and 8 provide the maximum planning flexibility among the CC, IGCC and AFBC for a wide range of intermediate load applications. Development in phases results in short lead time and ability to match generation to system requirements. The first phase, CTU, of these two options can be developed for peaking applications. As demand increases or as gas price increases, the second phase can be added to provide additional capacity and improved efficiency. For Option 8, the third phase can be added to produce synthesis gas from lower cost coal, thus providing flexibility of fuel switching and economy at higher ACF operations.

Both options have environmental characteristics that are equal to or better than CSC options.

Ontario Hydro has no direct experience with either option, but considerable experience exist worldwide for the CC, even though commercial application of the IGCC concept is limited. By developing in phases, implementation of the third phase can be postponed to allow sufficient time for Hydro to gain confidence in the IGCC as it matures.

Rationale for Not Selecting Options 7, 9 and 10

Option 7 is designed for peaking applications and is represented by Option 6 for intermediate load applications. Similarly, Option 9 is intended for base load applications and is represented by Option 8 for peaking and intermediate load applications.

Option 10 is not economic and does not have any environmental advantages over other options for intermediate load applications. Hence it is not selected for inclusion in plan development.

Summary

Seven major supply options are selected from among the fourteen purchase, fossil, and nuclear options for plan development. These seven options are classified by the system application to which they are most suited. For base load applications four options are selected:

- Option 1 – 4x800 MW US coal-fueled CSC with FGD and SCR;
- Option 9 – 4x660 MW unphased IGCC with SCR;
- Option 11 – 4x881 MW CANDU; and
- Option 13 – 1000 MW Manitoba purchase.

For intermediate load applications, two options are selected:

- Option 6 – 2x660 MW CC with SCR; and
- Option 8 – 4x660 MW phased IGCC.

For peaking load applications, one option is selected:

- Option 5 – 2x150 MW gas-fueled CTU.

In addition to the above, some of the 7 options are suitable for other applications. Options 1 and 11 are also suitable for high intermediate load applications. The first phase of Options 6 and 8 are also suitable for peaking load applications.

SITING CONSIDERATIONS

The purpose of this section is to discuss the siting implications of the selected fossil and nuclear options in the plans that are discussed in Chapter 15. Existing and identified sites are considered for illustrative purposes to ensure that cost estimates are realistic and comprehensive.

The following topics are discussed with respect to fossil and nuclear sites:

- technical and economic criteria for generating station sites;
- five different categories of sites in the Major Supply Plan;
- how illustrative sites have been used to develop the Major Supply Plan;
- candidate sites;
- new sites;
- site categories and sites; and
- siting considerations for future specific projects.

The siting of generating stations may be influenced by the transmission system and vice versa. The next section will discuss the general transmission system and the implications to the sites identified in this section.

Technical and Economic Criteria

Social, environmental, economic and technical considerations all enter into the selection process for generating station sites. Local consultations will be conducted in the course of siting studies, which will assist in the preparation of site specific environmental assessments. To be acceptable for further consideration, potential sites must first meet some basic technical and economic criteria. These siting criteria are applied to identify the sites assumed in formulating plans. They are also used to identify areas in which new sites may be located.

The following is a brief description of the basic technical and economic criteria:

Geographical balance between generation and load

Sites should maintain a geographical balance of generation and load to achieve operating flexibility and overall system reliability, and reduce new transmission requirements and transmission losses.

Limited generation at one site

No site should exceed 35% of the total system generation requirements in its annual energy production. Larger concentrations of generation at one site would endanger bulk power system reliability and security.

Physical requirements for specific options

Each option has certain physical requirements, such as:

- Adequate cooling water;
- Sound foundation;
- Adequate land; and
- Transportation access.

Infrastructure and access for the delivery of major equipment, construction material, and large quantities of fuel are necessary.

Reliable transmission incorporation

The distance of a site from the existing transmission system and the balance between generation and load in broad areas of the province are two important aspects of transmission incorporation. Sites should either have existing transmission facilities or provision for connection to the Bulk Transmission System. Maintaining a regional balance between load and generation reduces, but does not eliminate, the requirement for inter-area transmission facilities.

Effective land use

Sites should be utilized optimally. Large sites should be reserved for the larger major supply options such as multi-unit CSC, IGCC and CANDU. Smaller sites should be used to accommodate the smaller options such as CTU and CC. Existing fossil sites should be utilized to the extent practical and made available for reuse when they are retired or decommissioned.

Lead time

Existing Hydro sites have shorter lead time than new sites that Hydro has to acquire, especially if there is an operating station already on the site with all the related infrastructure. Lead time considerations are very important, especially when siting options like CTUs under upper load growth.

Cost

In developing the cost estimates for the major supply options, general economic implications of sites are considered.

Site Categories

The following five site categories are used in the development of Major Supply Plans:

Existing Stations/Sites – Available For Expansion

All existing stations and their associated sites have been examined to determine whether or not they are suitable for expansion for one or more of the six selected fossil and nuclear options. Existing fossil stations are particularly suitable for short lead time CTU to meet upper load growth. They offer economy through the use of skilled trades and operators already located at these sites and maximize the use of existing transmission land and other station service facilities. To be suitable for CTUs these sites must also be accessible to natural gas pipelines and have space for oil storage.

Existing Sites – Without Station

This category includes existing Ontario Hydro sites suitable for installation of one or more of the selected fossil or nuclear options. Wesleyville A and B are the only two sites in this category at this time.

Existing Stations/Sites – Available For Redevelopment in Plan Period

In the 25-year planning horizon, some of the existing stations will reach the end of their economic lives. Ontario Hydro will consider these sites for redevelopment of future generation options.

New Identified Sites

For reasons discussed later in this chapter, this category includes all new sites where the approximate location has been identified to be suitable for installation of one or more of the selected fossil or nuclear options. The North Channel area is the only one in this category at this time.

New Unidentified Sites

This category includes all new sites where only the general geographical area suitable for installation of one or more of the selected fossil or nuclear options is defined. Geological balance between generation and load, and transmission considerations, discussed in the next section, restrict the location of these sites to the southwest and northwest of Toronto. Because of cooling water requirements, these sites are likely to be situated on the north shore of Lake Erie, east shore of Lake Huron, or south shore of Georgian Bay.

Sites Are Illustrative

Candidate sites are identified which meet the technical and economic criteria. Generally, the intent is not to propose actual, specific sites for generation options. It is only to illustrate that it is technically and economically feasible to site the selected options within the province.

In developing the cost estimates for major supply options, illustrative sites are used. Darlington B and North Channel are used for the nuclear options, while Wesleyville and North Channel are arranged for the fossil options. The use of two sites provides a range of meaningful cost estimates for each option.

Candidate Sites

Candidate sites are known sites that are being considered for future fossil and nuclear generating facilities in the three candidate plans. Candidate sites are used in developing the major supply plans.

Candidate Sites for Nuclear Option

The following sites can accommodate a 4x881 MW CANDU station:

Darlington B (near Bowmanville)

- one existing CANDU station on site
- no additional site acquisition required
- near load growth area
- shortest lead time for a nuclear facility
- could be incorporated on existing rights-of-way

Wesleyville A & B (near Port Hope)

- no existing station on site
- some additional site acquisition may be required
- near load growth area
- could be incorporated on existing rights-of-way

Bruce C (between Kincardine and Port Elgin)

- two existing CANDU stations on site
- no additional site acquisition required
- reasonably close to major load centre
- would require new transmission rights-of-way
- generation concentration would exceed the criterion of limited generation at one site, can only be considered for use toward the end of the 25-year planning period

North Channel Area (between Bruce Mines and Espanola)

- not an existing Hydro site, but several potential sites in the area were investigated in 1978
- physically can accommodate two stations, but the requirement for geographical balance between generation and load limits development to one station
- relatively long distance from major load centre
- would require new transmission rights-of-way
- longer lead time due to need for site acquisition and preparation

Fig. 14.[illegible] Site Categories and Sites

Site Category	Sites	Conversion Process*
(1) Existing Stations/Sites – Avilable for Expansion	Dalington B	CANDU
	Lambton	CTU/NC
	Bruce C	CANDU
	Hearn	CTU/NC
	Keith	CTU/NC
	Nanticoke	CTU/NC
	Lennox A	CTU/NC
	Lennox B	CSC or IGCC
(2) Existing Sites – Without Station	Wesleyville A	CANDU or CSC or IGCC
	Wesleyville B	CANDU or CSC or IGCC
(3) Existing Stations/Sites – Available for Redevelopment	Hearn	CTU/CC
	Keith	CTU/IGCC
	Lambton	CSC or IGCC
	Lakeview	CSC or IGCC
(4) New Identified Sites	North Channel Area	CANDU or CSC or IGCC
(5) New Unidentified Sites	New Site1	CANDU or CSC or IGCC
	New Site 2	CANDU or CSC or IGCC
	New Site 3	CANDU or CSC or IGCC

**CTU/NC – CTUs with no provisions for conversion*
CTU/CC – CTUs convertible to combined cycles
CTU/IGCC – CTUs convertible to combined cycles or IGCCs

Candidate Sites for CSC and IGCC Options

The following sites can accommodate at least one CSC or IGCC station:

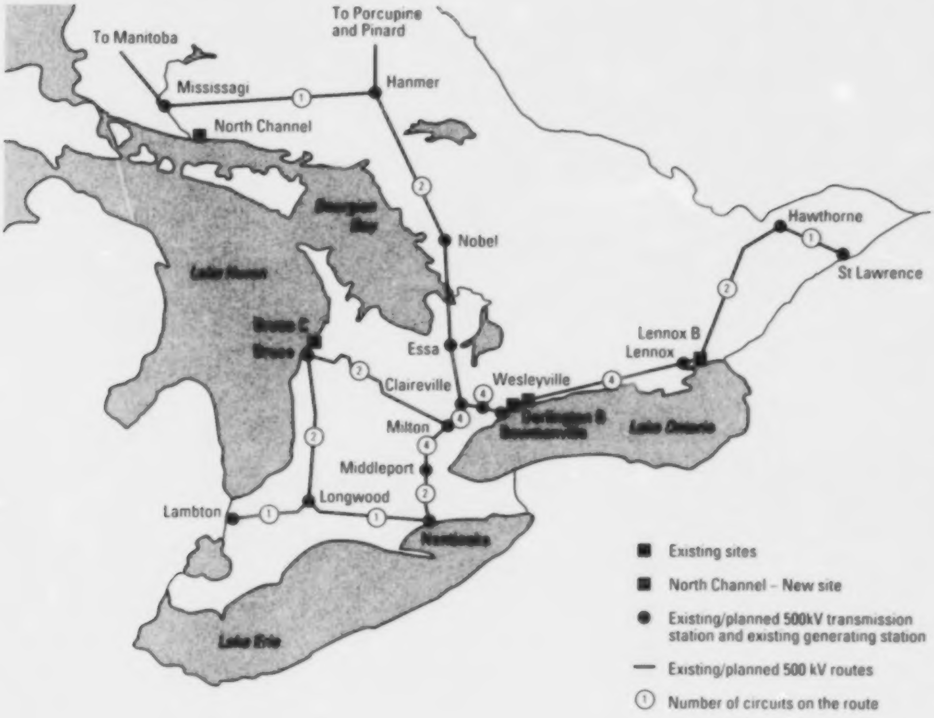
Wesleyville A & B (near Port Hope)

- no existing station on site
- some additional site acquisition may be required
- near load growth area
- could be incorporated on existing rights-of-way

Lennox B (near Bath)

- oil-fired Lennox A on same site
- no additional site acquisition required
- reasonably close to major load centre
- could be incorporated on existing rights-of-way

Figure 14–23 **Major Transmission in Year 2000**


To Manitoba
To Porcupine and Pinard
Mississagi
Hanmer
North Channel
Georgian Bay
Nobel
Hawthorne
St Lawrence
Lake Huron
Bruce C
Bruce
Essa
Lennox B
Lennox
Wesleyville
Claireville
Milton
Darlington & Bowmanville
Lake Ontario
Middleport
Longwood
Lambton
Nanticoke
Lake Erie
Existing sites
North Channel – New site
Existing/planned 500kV transmission station and existing generating station
Existing/planned 500 kV routes
Number of circuits on the route

North Channel Area (between Bruce Mines and Espanola)

- not an existing Hydro site, but several potential sites in the area were investigated in 1978
- physically can accommodate two stations, but the requirement for geographical balance between generation and load limits it to one
- relatively long distance from major load centre
- would require new transmission rights-of-way
- longer lead time due to need for site acquisition and preparation

Retired Stations

- The existing fossil generating station sites (Keith, Lakeview, and Lambton) could be used for new stations after the existing stations are decommissioned

Candidate Sites for CTU and CC Options

Some sites such as Hearn and Keith cannot accommodate IGCC or larger stations. These sites, however, are suitable for the addition of combustion turbine units which can be converted to combined cycle generation. In the case of Keith, if the site is redeveloped, it could possibly accommodate a small IGCC station. To meet the upper load forecast, Hydro requires options with very short construction times (2 years). This, in turn, would suggest installing combustion turbine units on operating station sites to shorten the in-service time. Existing operating stations – Lakeview, Lambton, Lennox A and Nanticoke – offer a short lead time option for the following reasons:

- the required land is already available;
- trained maintenance and operating staff are already on site;
- incorporating transmission is already in place, being planned or requires only minor modifications;
- maintenance shops, administrative buildings and other station service facilities are in place; and
- natural gas can be supplied through connections to existing pipelines in the vicinity of these stations and some space is available for oil storage.

Hearn and Keith are currently mothballed and do not have trained maintenance and operating staff on site. In short lead-time situations CTUs could be installed at these sites. However, these two stations are better suited for the longer lead time development of combined cycle stations using current facilities or redevelopment of the sites. This better site utilization may be precluded by the installation of non-convertible CTUs. The following existing fossil stations are potentially suitable for CTUs:

- Hearn (Toronto) – CTU/CC (Phase 1)
- Keith (Windsor) – CTU/IGCC (Phase 1)
- Lambton (Sarnia) – CTUs
- Nanticoke (Port Dover) – CTUs
- Lennox (Bath) – CTUs
- Lakeview (Mississauga) – CTUs

As noted earlier, the lead times for these options and sites would be shorter than for the larger nuclear, CSC and IGCC stations. These options and sites should be retained for flexibility to meet higher load growth or other supply contingencies.

New Sites

The requirement for sites is identified in Chapter 15. The number of sites required for base load stations varies from 1 to 4 depending on the load growth and the candidate plan selected. The majority of existing sites available are east of Toronto – Lennox B, Wesleyville A, Wesleyville B, and Darlington B. Existing generation is already concentrated along Lake Ontario east of Toronto – Pickering A, Pickering B, Darlington, Lennox and Saunders GS.

To maintain a reasonable balance between generation and load, it is preferable to limit base load expansion east of Toronto to one station at the beginning of the 25-year planning period. It is preferable to limit the North Channel development to one base load station because of load distribution and transmission considerations. For these reasons, the preferred locations for base load stations would be southwest and northwest of Toronto. Considering the need for cooling water, the preferable locations for new sites are along the north shore of Lake Erie, the east shore of Lake Huron, and the south shore of Georgian Bay.

Sites may be considered on Lake Superior but they are less attractive due to the small proportion of system load in that area and the long distance to the major load centres in southern Ontario.

Site Categories and Associated Sites

Figure 14–22 lists the 15 alternative sites, their site categories, and the conversion process for which they are suitable.

Approvals

Approvals requested in this application (see Chapter 19) include the requirement and rationale for the stations and sites in the Hydraulic Plan, and the requirement and rationale for new fossil and nuclear generation. Locations to be considered for the various fossil and nuclear projects will include at least those sites shown in Figure 14–22. Approvals are also requested for the requirement and rationale for radial transmission to incorporate new generation to the existing and planned bulk transmission system. Subsequent project assessments will ensure that the approved facilities are located and implemented in an environmentally acceptable manner, and with opportunities for community input. Project assessments will not duplicate or reconsider the planning issues determined by this application.

Siting Considerations for Future Specific Projects

In implementing its Proposed Major Supply Plan, Ontario Hydro will give attention to community and environmental factors in the process of site selection. The siting process will reflect good corporate citizenship and partnership with communities. Hydro will work toward achieving a compatible fit between the proposed facilities and local community and environmental circumstances. This will include:

- Ensuring public health and safety and the protection of environmental quality;
- Providing opportunities for communities to volunteer to be the site of a proposed facility; and
- Communicating to the public the full range of issues associated with Hydro's site activities and working with communities on matters that affect them.

Hydro facilities have social and environmental impacts. Detailed studies will be required to assess fully the particular impacts associated with potential sites. Hydro has policies and practices for working with communities to address potential impacts. These include:

- Eliminating or managing impacts through agreements with local communities and through other institutional arrangements with government agencies and ministries;
- Enhancing or creating beneficial effects such as local employment and infrastructure, where possible; and
- Consulting with local communities on matters which affect them in the site selection, construction, and operations phases of stations, using a variety of community liaison measures. For example, liaison committees consisting of community and Hydro representatives have been used to identify and address concerns and opportunities at existing stations.

TRANSMISSION CONSIDERATIONS

Previous sections identified selected supply options for consideration in developing plans and potential sites suitable for accommodating these options. It was recognized that the siting of generating stations has an impact on the transmission system and therefore transmission considerations must be included in generation siting. The purpose of this section is to discuss the following:

- basic purposes of the transmission component of the Bulk Electricity System (BES);
- the integrated transmission system;
- distinction between the radial transmission[†] necessary to connect a new site into the BES and inter-area[†] transmission necessary to maintain an integrated BES; and
- transmission requirements to connect specific sites to the BES and the implications of generating siting on the need for inter-area transmission.

Transmission Purposes

The bulk electricity transmission system (BES) is the integrated system of transmission lines and stations by which electric power is delivered from major generating stations to and between load centers, and is delivered to and from interconnections with neighbouring utilities.

The purpose of the bulk transmission system is:

- to deliver power to meet forecast growth in customer demand, recognizing regional variations in rates of growth;
- to incorporate new sources of power generation or purchases to the integrated transmission network to ensure economic and reliable use of such generation or purchases;
- to integrate the Hydro BES with neighbouring utilities through interconnections with these utilities to permit economic and reliability improvements; and
- to permit optimum use of available generation and purchases in accordance with changing customer demands and environmental restrictions.

Integrated Transmission System

The primary reasons for developing an integrated transmission system are to permit the most economical use of stations and to maintain adequate reliability of supply to area loads in the event of station and transmission component failures.

The major transmission facilities shown in Figure 14–23 provide a strong base system for incorporating the demand and supply options under consideration. However, additional bulk transmission facilities will be required beyond 2000 to meet growth in customer demand and to incorporate new supply options, including the hydraulic program, major purchases and new fossil and nuclear generating stations. Both the nature and timing of these transmission facilities will be influenced by the timing, location, and conversion process, or alternatively – generation type, of the next and subsequent generating stations.

Transmission Classification

The transmission required to incorporate a new Ontario Hydro generating station will include radial transmission necessary to connect the site to the existing and planned BES. It may also include inter-area transmission necessary to maintain an integrated BES. The need for radial transmission is driven solely by the choice of site and its proximity to a suitable existing or planned transmission station in the integrated system. The need for inter-area transmission can also be driven by the choice of site, but is also concerned with many other factors such as security and reliability of load supply, geographic mismatch of load and generation, and operational flexibility and economics. As such, this transmission is governed by area load growth and existing capacity considerations in addition to the siting of new generation.

To illustrate the differences between the two components of radial and inter-area transmission, examples of the facilities required to incorporate a generating station at an existing site and at a new site are given below:

Lennox B (4 x 800 MW CSC)

- The required *radial* transmission would consist of new 500 kV lines (less than 1 km) on existing right-of-way to connect the new generating station into the local existing and planned 500 kV lines.
- In addition to the existing and planned 500 kV transmission from the Kingston area (Lennox) to Bowmanville (Darlington), a third double-circuit 500 kV line (46 km) would be required between Bowmanville Switching Station and Cherrywood Transformer Station (Toronto) on an existing right-of-way. This new transmission would be needed to accommodate the increased power flows from this new station and the existng stations east of Toronto. This new transmission is classified as *inter-area* transmission.

North Channel Area (4x881MW CANDU)

- The *radial* transmission required is two 500 kV single circuit lines (50 km) from the new site to the existing Mississagi Transformer Station (near Sault Ste. Marie) on a new right-of-way and two 500 kV single circuit lines (225 km) from the new site to the existing Hanmer Transformer Station at Sudbury on a new right-of-way.
- To accommodate the increased power flows on the existing bulk transmission system due to the new station and the Manitoba Purchase, new hydraulic developments and the purchase of non-utility generation in northern Ontario, would require new *inter-area* transmission. This would require a new 500 kV single circuit line (210 km) from Sault Ste. Marie to Sudbury on existing right-of-way and two new 500 kV single circuit line (400 km) from Sudbury to Toronto on a new right-of-way.

It should be emphasized that the above examples are for illustrative purposes only.

Approvals

The transmission approvals requested in this application (Chapter 19) are for the requirement and rationale for radial transmission. Specific routes for this radial transmission will be assessed as part of the project specific environmental assessment for each generation development.

Where required, approvals for inter-area transmission will be sought in separate parallel processes. Although other factors must also be considered, timing of the inter-area transmission is influenced by the location of the generating stations. Therefore, approvals must be obtained to permit required new inter-area transmission to be in service prior to connecting the new generating station to the BES.

HIGHLIGHTS

From among the fourteen purchase, fossil, and nuclear options, seven major supply options are selected to be carried forward to plan development. These seven options are classified by the system application for which they are most suited. For base load applications, four options are selected:

- Option 1 – 4x800 MW US coal-fueled CSC with FGD and SCR
- Option 9 – 4x660 MW unphased IGCC with SCR
- Option 11 – 4x881 MW CANDU
- Option 13 – 1000 MW Manitoba purchase

For intermediate load applications, two options are selected:

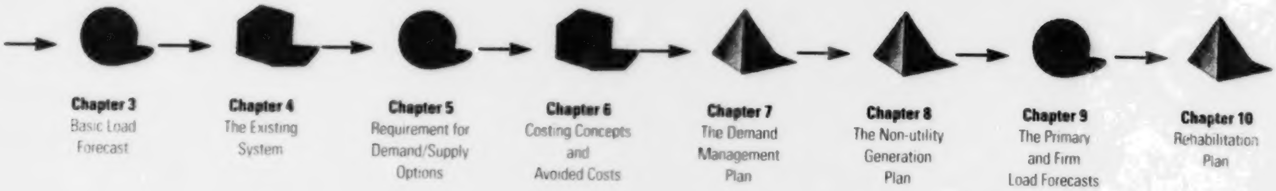
- Option 6 – 2x660 MW CC with SCR
- Option 8 – 4x660 MW phased IGCC

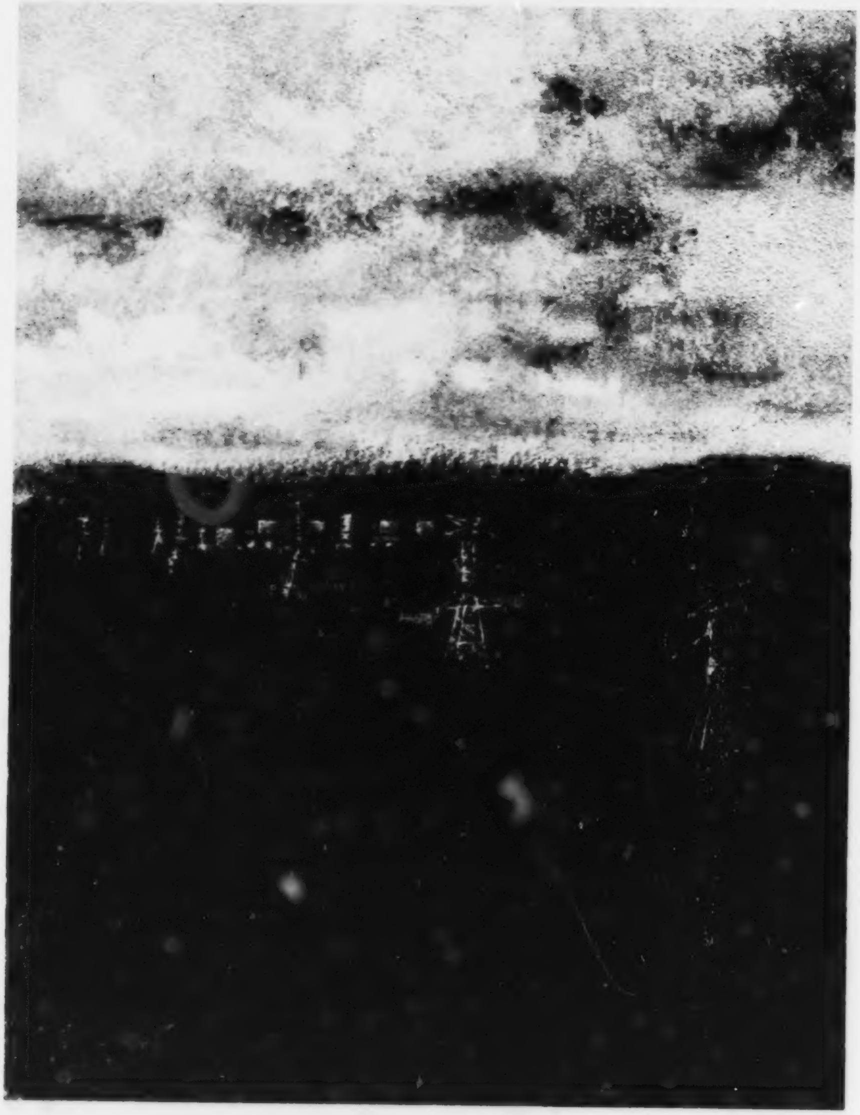
For peaking load applications, one option is selected:

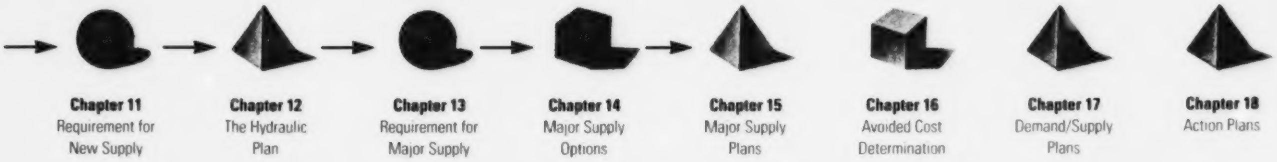
- Option 5 – 2x150 MW gas-fueled CTU

In addition to the above, some of the 7 options are suitable for other applications. Options 1 and 11 are also suitable for high intermediate load applications. The first phase of Options 6 and 8 are also suitable for peaking load applications.

Based on known sites,and the existing and proposed bulk transmission system, it is technically and economically feasible to site and incorporate the selected fossil and nuclear options. Due to the limited number of suitable identified sites, studies are being undertaken to identify sufficient new sites to provide flexibility in siting the options in the Candidate Plans. ■


Chapter 3
Basic Load Forecast
Chapter 4
The Existing System
Chapter 5
Requirement for Demand/Supply Options
Chapter 6
Costing Concepts and Avoided Costs
Chapter 7
The Demand Management Plan
Chapter 8
The Non-utility Generation Plan
Chapter 9
The Primary and Firm Load Forecasts
Chapter 10
Rehabilitation Plan




Chapter 11
Requirement for New Supply
Chapter 12
The Hydraulic Plan
Chapter 13
Requirement for Major Supply
Chapter 14
Major Supply Options
Chapter 15
Major Supply Plans
Chapter 16
Avoided Cost Determination
Chapter 17
Demand/Supply Plans
Chapter 18
Action Plans

15 Major Supply Plans

The purpose of this chapter is to explain how options are formulated into plans, and to provide the rationale for alternative plans, and the selection of the Proposed Major Supply Plan.

The characteristics of the seven options selected for incorporation into plans are summarized in Figure 15-1. This chapter describes the various elements in the development of major supply plans in the following sections:

- Planning criteria
- Formulation process
- Formulation considerations
- Cases formulated
- Description of major supply cases
- Capacity and energy contribution
- Illustrative siting
- Illustrative transmission
- Comparison of the cases
- Selection of candidate major supply plans
- Selection of the proposed major supply plan

Criteria for design and evaluation of plans are identified in the Demand/Supply Planning Strategy. Discussion of the application of these criteria is the subject of this chapter. Information on the criteria is provided in the Demand/Supply Planning Strategy Report.

Major supply plans are formulated to put in place options to satisfy the requirements for peak power and energy established in Chapter 13. The criteria and the considerations set out below were used to incorporate the major supply options into Cases[†] to meet this objective.

Figure 15-2 illustrates the Case and plan formulation process. Dozens of Cases were developed for analysis. Some were dropped because they produced poor results or did not meet primary criteria. Remaining Cases were evaluated and revised to produce the Cases presented in this chapter.

Computer models were used to simulate each Case, showing how new major supply options would work with the existing system and the Demand Management, Non-Utility Generation and Hydraulic Plans identified in previous chapters. These simulations were then analyzed and further Cases were developed to illustrate alternatives or to pursue improvements. This process was repeated until Cases were identified which provided good illustrations of alternative approaches.

Generation Type	Option Number	Conversion Process	Primary Energy	Environmental Control	Configuration	System Application		
						Peak	Inter-mediate	Base
Fossil	1	CSC	US coal	FGD & SCR	4 x 800 MW	–	*	*
	5	CTU	gas/oil	–	2 x 150 MW	*	–	–
	6	CC	gas/oil	SCR	2 x 660 MW	–	*	–
	8	phased IGCC	gas/oil/ US coal	–	4 x 660 MW	*	*	–
	9	unphased IGCC	US coal	SCR	4 x 660 MW	–	–	*
Nuclear	11	CANDU	uranium	contained by design	4 x 881 MW	–	*	*
Purchase	13	Hydraulic	water	–	1000 MW	–	–	*

Primary Criteria

The primary criteria (which must be met) for evaluating and developing recommended plans are:

- customer satisfaction
- reliability standards
- safety requirements and standards (worker and public)
- environmental requirements and standards
- low cost of electricity service
- social acceptance
- technical soundness
- flexibility

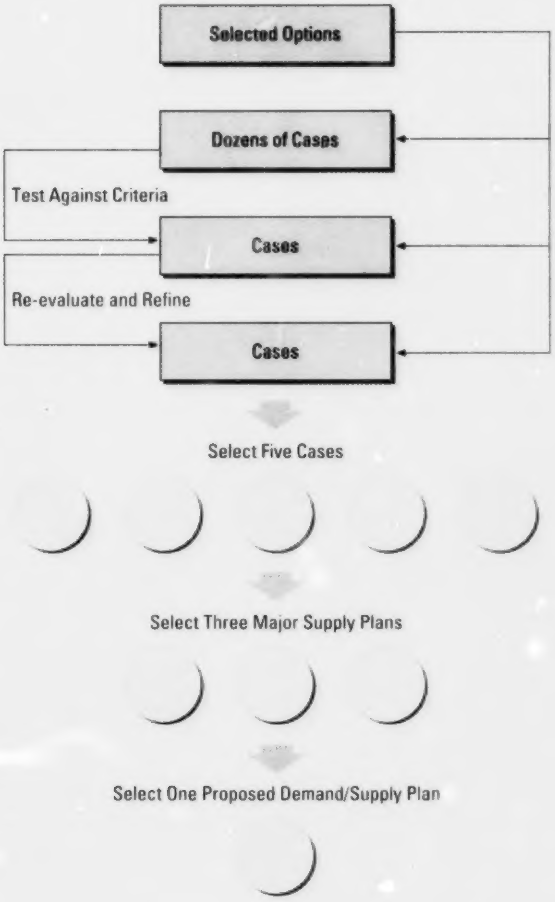
Secondary Criteria

Secondary criteria, which are considered and may influence the recommended plans, include:

- resource preferences
- diversity
- resource smoothing
- environmental characteristics (in addition to requirements and standards)
- public safety characteristics (in addition to requirements and standards)
- economic impact
- other social considerations

Secondary criteria, which do involve considerable judgement, have had a significant effect in the evaluation of plans and options.

Figure 15–2 **Case and Plan Formulation Process**


Selected Options
Dozens of Cases
Test Against Criteria
Cases
Re-evaluate and Refine
Cases
Select Five Cases
Select Three Major Supply Plans
Select One Proposed Demand/Supply Plan

In addition to the criteria, the following were also important considerations in formulating Cases:

- customer use patterns
- bandwidth forecast
- integration with existing system and other plans
- reserve margins
- option lead times
- oil and gas uncertainty
- acid gas regulations
- radioactivity
- greenhouse gas emissions
- capacity diversity and energy diversity
- siting
- transmission

Following are descriptions of these considerations.

Customer Use Patterns

To meet customer patterns of electricity use, peak, intermediate and base load generation are required. Hydro strives to achieve an appropriate mix of generation. Some supply options can serve one of these applications economically, but may be expensive if used for others.

An appropriate mix is achieved when each type of generation operates at its most economic capacity factor. Figure 15–3 shows, for example, that the CANDU offers lowest cost at 50% – 80% capacity factor, CSC coal option is lowest at 25% – 50% capacity factor, and the CTU gas option is lowest at capacity factors of 25% and less.

Capacity factors of existing units are influenced by the type of generation added. For example, a new base load unit could meet the load forecast and some of the load handled by existing units that are more expensive to operate. As a result, the more expensive units would be operated at a lower capacity factor. Alternatively, if a peaking unit is added, existing peaking and intermediate units might be required to work harder to meet the load.

The quantity of new generation that must be added in any year to meet the supply need, including a reserve margin, is given in Chapter 13.

Bandwidth Forecast

Each Case was tested against the bandwidth forecast, consisting of five electricity demand paths (Figure 15–4). One path assumes demand follows the median load forecast; one assumes demand follows the upper load forecast; and one assumes a lower load forecast. A fourth path assumes that demand starts out on the median forecast, but in 1995 branches toward the upper. A fifth path does the same, but branches toward the lower load path.

These five paths test the ability of each Case to accommodate changes in forecast electricity demand. If load rises more quickly than the median, then additional generation is added, if possible. If load grows slower than the median, new generation is deferred or existing generation is mothballed.

Cases were rejected which were designed primarily to meet the upper forecast. Such Cases would have enough generation to meet all criteria as economically as possible under the upper load forecast, but would be overbuilt and have excessive costs under median or lower load forecast.

Cases designed primarily to meet the median load forecast were rejected, because they would not include the early preparatory work that provides the flexibility to meet the upper forecast.

Figure 15–3 **Levelized Unit Energy Cost of Major Supply Options**
(In-service Date 2002)

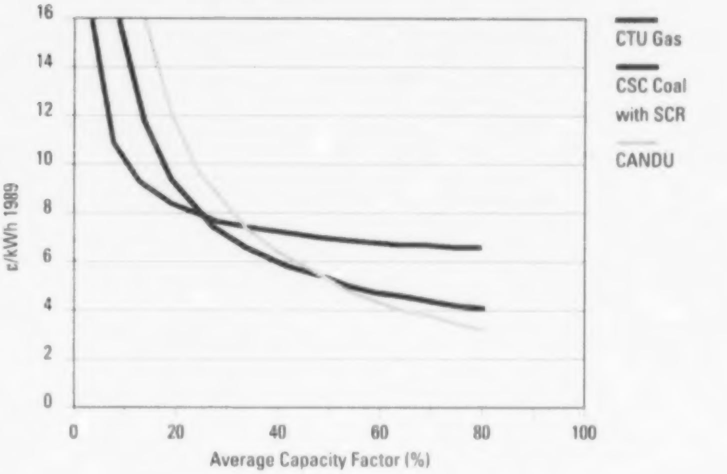
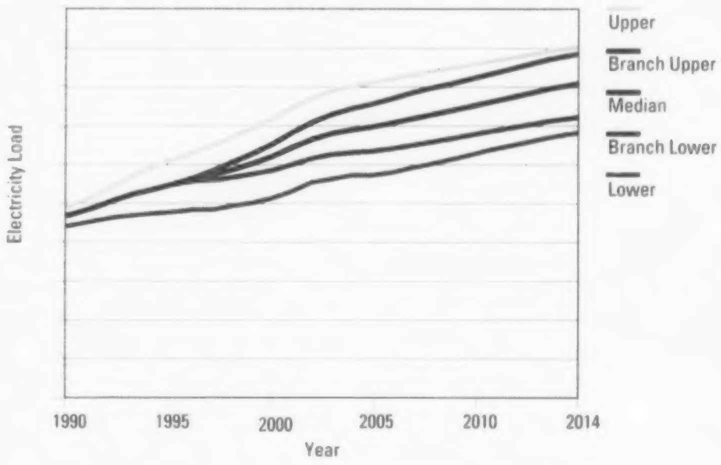


Figure 15–4 **Load Forecast Paths Used to Formulate Cases**



[illegible]

System Application	Total Capacity Required		Median Load Forecast Existing Capacity Still In-service		New Capacity Required	
	2005	2014	2005	2014	2005	2014
Base	18.0	21.3	14.1	12.0	3.9	9.3
Intermediate	4.5	4.2	8.7	3.3	-4.2	0.9
Peaking	5.8	7.2	2.5	2.4	3.3	4.8
Totals	28.3	32.7	25.3	17.7	3.0	15.0

Cases designed primarily to meet the lower load forecast were rejected because, under the median or upper load forecast, these Cases would have poor reliability, high cost and would not meet environmental requirements.

Attention focused on those Cases which kept costs low over the full load forecast bandwith, while providing good flexibility and environmental performance.

Integration with Existing System and Other Plans

Existing fossil-fueled stations, equipped with some emission controls, are now used to meet both peak and intermediate requirements. With the addition of major new supply, the existing fossil stations will be best suited to the intermediate role. Figure 15–5 shows there is adequate existing fossil generation to meet intermediate requirements under the median load forecast to 2005. Insufficient intermediate capacity starts in 2013.

Reserve Margins

All Cases aim to have reliability reserve margins of about 24% of firm load. This reserve margin gives customers the least cost when the cost of providing electricity and the costs to the customer of electricity interruptions are taken into account.

Option Lead Times

Figure 15–6 shows lead times required to put new generation in place. Eight to fourteen years are required to install new nuclear and CSC coal base load options. As a result, it is difficult to respond to higher demand in the next few years with these options. Quicker response is possible with CTUs as the first phase of an IGCC, but even this option requires lead times of five to nine years. For flexibility to respond to higher demands in the early and mid-1990s CTUs, on existing sites are preferred. They can be added in two to five years.

Oil and Gas Uncertainty

The price and availability of natural gas and oil is subject to greater uncertainty than either coal or uranium. At present, gas and oil are competitive fuels for peaking (CTU) and low intermediate applications (CC – Combined Cycle). As a hedge against the uncertainties surrounding oil and gas, CTUs are introduced on sites permitting conversion of the CTU into higher efficiency combined cycle units and coal gasification units. These steps would be taken if either intermediate or base load generation is required, or if the price of gas and oil becomes uncompetitive. All CTUs would have the ability to use oil in winter peak periods, when gas might not be available.

Acid Gas Regulations

Cases are designed to meet system-wide acid gas emission environmental requirements. Starting in 1994, total system emissions of sulphur dioxide must be less than 175 Gg each year, and the sum of total system emissions of sulphur dioxide and nitrogen oxides must be less than 215 Gg each year.

For existing stations, the reduced sulphur dioxide limits will be met by additional environmental control facilities and by burning low-sulphur fuels. New CSC coal stations will be equipped with high efficiency scrubbers to achieve an SO_2 emission rate of about 2 g/kWh.

All Cases feature NO_x controls appropriate to generation types and applications. For base load operation, new options must achieve a nitrogen oxide emission rate of 0.25 g/kWh. To meet this target, conventional steam cycle coal options will require selective catalytic reduction.

					Lead Time - Years To First Unit In-Service		
Option No.	**Conversion Process**	**Primary Energy**	**Phase**	**Site Size**	**Definition† Phase**	**Acquisition† Phase**	**Total**
1	CSC	US Coal	Unphased	Major	3 – 6	5 – 8	8 – 14
5	CTU/NC	Gas/Oil	Unphased	Minor	1 – 3	1 – 2	2 – 5
6	CC	Gas/Oil	Unphased	Medium	3 – 6	3 – 5	6 – 10
7	CTU/CC	Gas/Oil	First	Medium	3 – 6	2 – 3	5 – 9
8	CTU/IGCC	Gas/Oil	First	Major	3 – 6	2 – 3	5 – 9
9	IGCC	Coal	Unphased	Major	3 – 6	3 – 5	6 – 10
11	CANDU	Uranium	Unphased	Major	3 – 6	5 – 8	8 – 14
13	Utility Purchase	Manitoba Hydro	Unphased	–	–	–	9 – 12

Siting Size – Minor – site large enough for CTUs only
– Medium – site large enough for CCs only
– Major – site large enough for CSC, IGCC, or CANDU

Siting Preferences – CTU/Gs

CTU/NC – existing site, operating station, minor size site
– effective land use, trained staff on-site
– short lead time to meet upper growth

CTU/CC – existing site, medium size site
– effective land use
– medium lead time

CTU/IGCC – major site
– any site including decommissioned site

For stations with an expected capacity factor of less than 20%, the permissible emission rate is 1 g/kWh.

Radioactivity

A CANDU generating station is essentially a contained design in which the reactor systems are closed circuits within a containment building. Under normal operating conditions there are virtually no radionuclide emissions.

A CANDU generating station is designed to minimize radioactivity releases to the environment by providing stringent design and control systems that respond to the Atomic Energy Control Board licensing requirements. Typically, radionuclide emissions are less than 1% of AECB prescribed limits.

Long-term management of high level radioactive waste (i.e. used nuclear fuel) is currently the focus of a conceptual assessment being carried out by Atomic Energy of Canada Ltd. (AECL). The concept of deep underground disposal will be reviewed by a Federal Environmental Assessment Review Panel starting in 1991. Once the disposal concept is approved, site selection for a central repository can start. In the meantime, used fuel wastes can be adequately managed on-site at existing generating stations.

Low and intermediate level radioactive wastes are managed centrally (using incineration and a variety of storage methods) at the Bruce Nuclear Power Development (BNPD) waste management site on Lake Huron.

As there are ongoing public concerns with public safety and radioactive waste disposal, Cases were developed with few or no new nuclear stations.

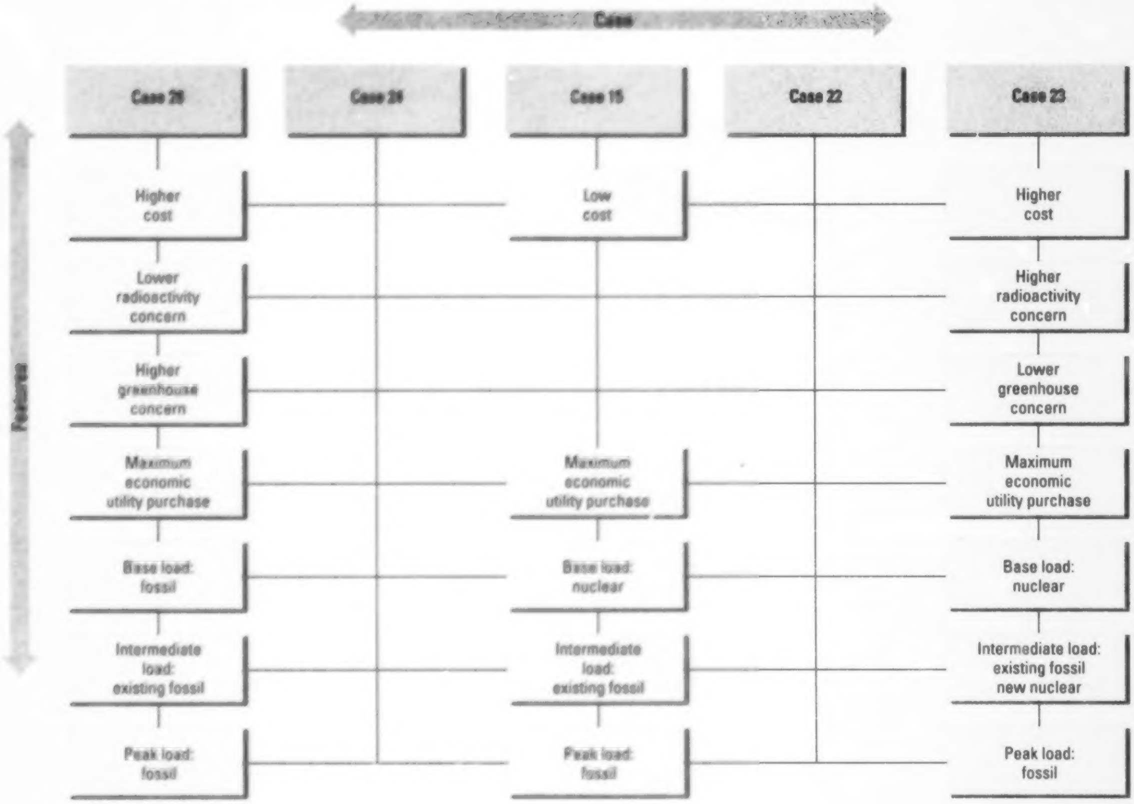
Greenhouse Gas Emissions

There are emerging concerns about the emission of greenhouse gases, particularly CO_2. Carbon dioxide is the principal gas produced by fossil combustion in producing electricity. There are no regulations governing these emissions, but an illustrative target cutting CO_2 by 20% of 1988 levels by 2005 has been put forward by federal and provincial ministers. Cases to illustrate possible CO_2 emission reductions were developed with minimum new fossil generation and low use of existing fossil units.

Capacity Diversity and Energy Diversity

The generation mix of utilities varies widely. Some utilities have 100% reliance on hydraulic stations, others a 100% reliance on fossil-fueled stations. Electricité de France relies more than 70% on nuclear stations. High dependence on one generation type is usually pursued because of its low cost. The capacity diversity

Figure 15–7 **Major Supply Plan Features**


Case
Features
Case 20
Case 24
Case 15
Case 22
Case 23
Higher cost
Low cost
Higher cost
Lower radioactivity concern
Higher radioactivity concern
Higher greenhouse concern
Lower greenhouse concern
Maximum economic utility purchase
Maximum economic utility purchase
Maximum economic utility purchase
Base load: fossil
Base load: nuclear
Base load: nuclear
Intermediate load: existing fossil
Intermediate load: existing fossil
Intermediate load: existing fossil new nuclear
Peak load: fossil
Peak load: fossil
Peak load: fossil

of Ontario Hydro's system is greater than that of most utilities in North America.

During the 1970s, Ontario Hydro adopted a criterion limiting the nuclear option to two-thirds of additional capacity. This criterion offers a balance between low cost and low acid gas emissions on one hand, and too much dependence on the nuclear option and its associated radiation concerns on the other hand. Greenhouse gases were not a consideration in the 1970s. However, future regulations may require a reconsideration of this criterion.

Diversity in the primary energy sources used for electricity generation (coal, uranium, gas, oil, water) is desirable because it makes the system less vulnerable to factors such as droughts, strikes and regulatory restraints.

Siting

The sequence in which sites are developed influences costs, transmission requirements and lead times. To develop meaningful plans and identify the costs associated with those plans it is necessary to make assumptions as to where the proposed major new generation might be located. Representative locations were chosen for each major new facility from a number of potential sites. This selection was based on considerations such as cost, lead times, social and environmental acceptability, technical flexibility, proximity to load centres, constructability and the extent of new transmission to incorporate a proposed facility.

Transmission

The costs of representative transmission necessary to incorporate the proposed new generation into the Bulk Electricity System were also determined. These representative transmission plans were developed consistent with Ontario Hydro's planning criteria for the Bulk Electricity System.

Five Cases were formulated. They are summarized in Figure 15–7.

Manitoba Purchases Common to all Cases

All Cases feature the purchase of electricity from Manitoba. The present purchase arrangements start in 1998 at 200 MW, grow to 1000 MW by 2002, continue at that level until 2018, and will conclude in 2022. Depending on circumstances at the time, the contract could be renegotiated.

Case 15

This Case is designed to achieve both low air emissions and low cost. A mix of base load nuclear and peaking fossil options is used to achieve low acid gas and greenhouse emissions, low cost, flexibility, and capacity diversity. Intermediate load is met by existing fossil stations retrofitted, as required, with emission controls.

	Capacity (GW)		
Major Supply Option	Lower Forecast	Median Forecast	Upper Forecast
Utility Purchase	1.0	1.0	1.0
CANDU	5.3	8.8	12.3
CTU/NC	0	0	1.7
CTU/CC	1.0	1.0	2.0
CTU/IGCC	2.3	4.4	2.7
Total	9.6	15.2	19.7

Case 26

This Case is designed to respond to public perceptions and concern about public safety and radioactive waste. Therefore, this Case features no new nuclear generation. CSC coal-fueled generation meets base load requirements and gas-fueled CTUs meet peaking needs. Existing fossil generation meets intermediate requirements.

Case 23

This Case is designed to minimize greenhouse gas emissions. Nuclear stations meet the base load and some of the intermediate load requirements. Existing fossil generation handles the balance of intermediate needs and peaking needs. A minimum of new peaking fossil is added.

Case 24

This Case is designed to be between Case 26 and Case 15. It illustrates the impact of using a CSC coal station for the second major addition of base load plant. CANDU provides the other base load requirements.

Case 22

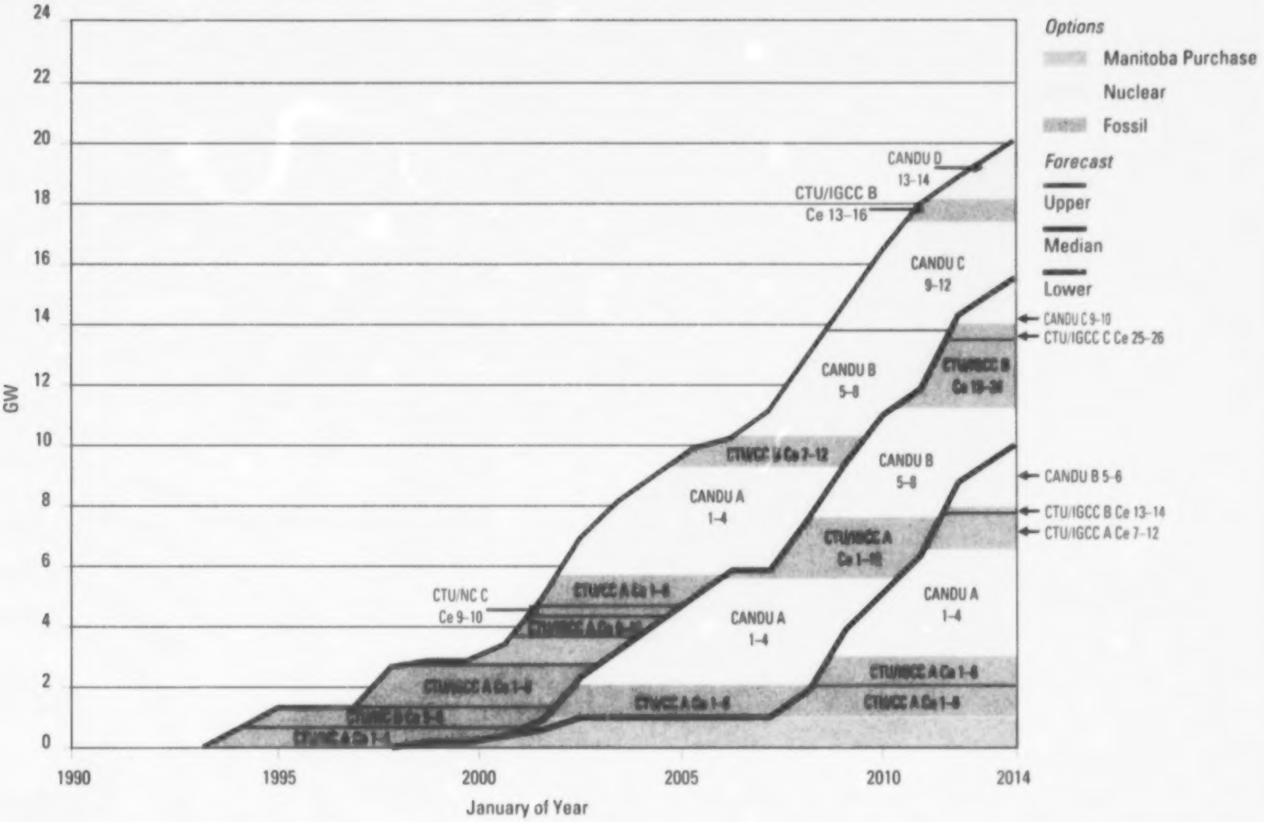
This case is designed to be between Case 15 and Case 23. It illustrates the impact of using, relative to Case 15, more nuclear generation and less fossil generation.

Case 15

In this Case, about two-thirds of the new capacity under each load forecast condition consists of purchases and base load nuclear generation, the remaining one-third is peaking fossil generation. Figure 15–8 summarizes the capacity additions.

Figure 15–9 illustrates the approximate timing of the major supply additions under the three load forecast paths.

Figure 15–9 **New Major Supply** Case 15



Under the median load forecast, base load requirement is supplied by nuclear generation with in-service dates set by cost and environmental considerations. The intermediate requirement is met by existing fossil stations, retrofitted as necessary to meet environmental requirements. The remaining peaking requirement is met with gas-fueled CTUs, convertible to CCs or IGCCs. In total, by 2014, this Case requires ten CANDU units at three stations, six CTU/CCs at one station and 26 CTU/IGCCs at three stations.

Under the upper forecast, options are advanced in the early years to the extent permitted by lead times. In later years, in-service dates are set by cost and environmental considerations. CTU/NCs at existing stations are used to reduce capacity shortfalls in the mid 1990s. These are followed by CTU/IGCCs on new sites starting in the late 1990s. More base load nuclear is added in later years to restore an appropriate mix of generation. In total, by 2014, this Case requires 14 CANDU units at four stations, ten CTU/NCs at three stations, 12 CTU/CCs at two stations, and 16 CTU/IGCCs at two stations.

Under the lower forecast, the requirements are met with fewer and later nuclear units and CTUs, whose in-service dates are set by cost and environmental considerations. The exception to delayed in-service dates is the

Lower Forecast

Option	Station	Units	Capacity (GW)	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
				Capacity Added By Year End (MW)									
Manitoba Purchase			1.000									200	
CTU/CC	A	1–6	1.008										
CTU/IGCC	A	1–12	2.016										
CANDU	A	1–4	3.524										
CTU/IGCC	B	13–14	0.336										
CANDU	B	5–6	1.762										
		Total (GW)	9.646										

Median Forecast

Option	Station	Units	Capacity (GW)	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
				Capacity Added By Year End (MW)									
Manitoba Purchase			1.000									200	
CTU/CC	A	1–6	1.008										
CTU/IGCC	A	1–12	2.016										
CANDU	A	1–4	3.524										
CTU/IGCC	B	13–24	2.016										
CANDU	B	5–8	3.524										
CTU/IGCC	C	25–26	0.336										
CANDU	C	9–10	1.762										
		Total (GW)	15.186										

Upper Forecast

Option	Station	Units	Capacity (GW)	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
				Capacity Added By Year End (MW)									
Manitoba Purchase			1.000									200	
CTU/NC	A	1–4	0.672				672						
CTU/NC	B	5–8	0.672					672					
CTU/IGCC	A	1–12	2.016								1344		
CTU/NC	C	9–10	0.336										
CTU/CC	A	1–6	1.008										
CANDU	A	1–4	3.524										
CTU/CC	B	7–12	1.008										
CANDU	B	5–8	3.524										
CANDU	C	9–12	3.524										
CTU/IGCC	B	13–16	0.672										
CANDU	D	13–14	1.762										
		Total (GW)	19.718										

Figure 15-[illegible] - Major Supply Additions By [illegible] – Case [illegible] (continued)

Lower Forecast — **Capacity Added By Year End (MW)**

2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
200	200	400											
								672	336				
									1008	336	336	336	
									881	881	881	881	
												336	
												881	881

Median Forecast — **Capacity Added By Year End (MW)**

2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
200	200	400											
	336	672											
		336						1680					
			881	881	881	881							
									1008	672		336	
									881	881	881	881	
												336	
												881	881

Upper Forecast — **Capacity Added By Year End (MW)**

2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
200	200	400											
336	336												
	336												
	672	336											
		881	881	881	881								
		336	336			336							
							881	881	881	881			
								881	881	881	881		
												672	
												881	881

Manitoba Purchase, for which contract commitments have been made. This Case requires by 2014 six CANDU units at two stations, six CTU/CCs at one station, and 14 CTU/IGCCs at two stations.

Figure 15–10 provides the in-service date of each unit.

Case 26

In this Case, about half of the new base load capacity under each load forecast condition consists of purchases and CSC coal. Peaking requirements are met by CTU/Gs. The proportion of peaking generation is larger than in Case 15, because the CSC coal station is smaller than a nuclear station and more CTUs are installed to compensate. Figure 15–11 summarizes capacity additions by 2014.

An alternative to Case 26 was developed using IGCC stations rather than CSC coal stations as base load fossil generation. The results of the two cases are similar, except for solid waste and technical soundness. IGCC features lower solid waste. CSC is more technically proven for early commercial application.

The approximate timing of capacity additions over the planning period is shown in Figure 15–12.

Under the median forecast, base load requirement is met with CSC coal generation. The intermediate requirement is met by existing fossil stations retrofitted with controls to meet environmental requirements. The remaining peaking requirement is met with gas-fired CTUs convertible to CCs or IGCCs. This Case requires by 2014 ten CSC Coal units at three stations, six CTU/CCs at one station, and 34 CTU/IGCCs at three stations.

Under the upper forecast, options are advanced in the early years, to the extent per-

[illegible]

	Capacity (GW)		
Major Supply Option	**Lower Forecast**	**Median Forecast**	**Upper Forecast**
Utility Purchase	1.0	1.0	1.0
CSC – Coal	4.5	7.4	10.4
CTU/NC	0	0	1.4
CTU/CC	1.0	1.0	2.0
CTU/IGCC	3.0	5.7	5.0
Total	9.5	15.1	19.8

[illegible]

CTUs are used to meet peaking requirements. To protect against the possibility of higher than forecast fuel prices or higher CTU capacity factors, provision is made to develop some of these CTUs, in phases, into combined cycle (CC) or integrated gasification combined cycle (IGCC) units. These provisions make it necessary to make the following distinctions:

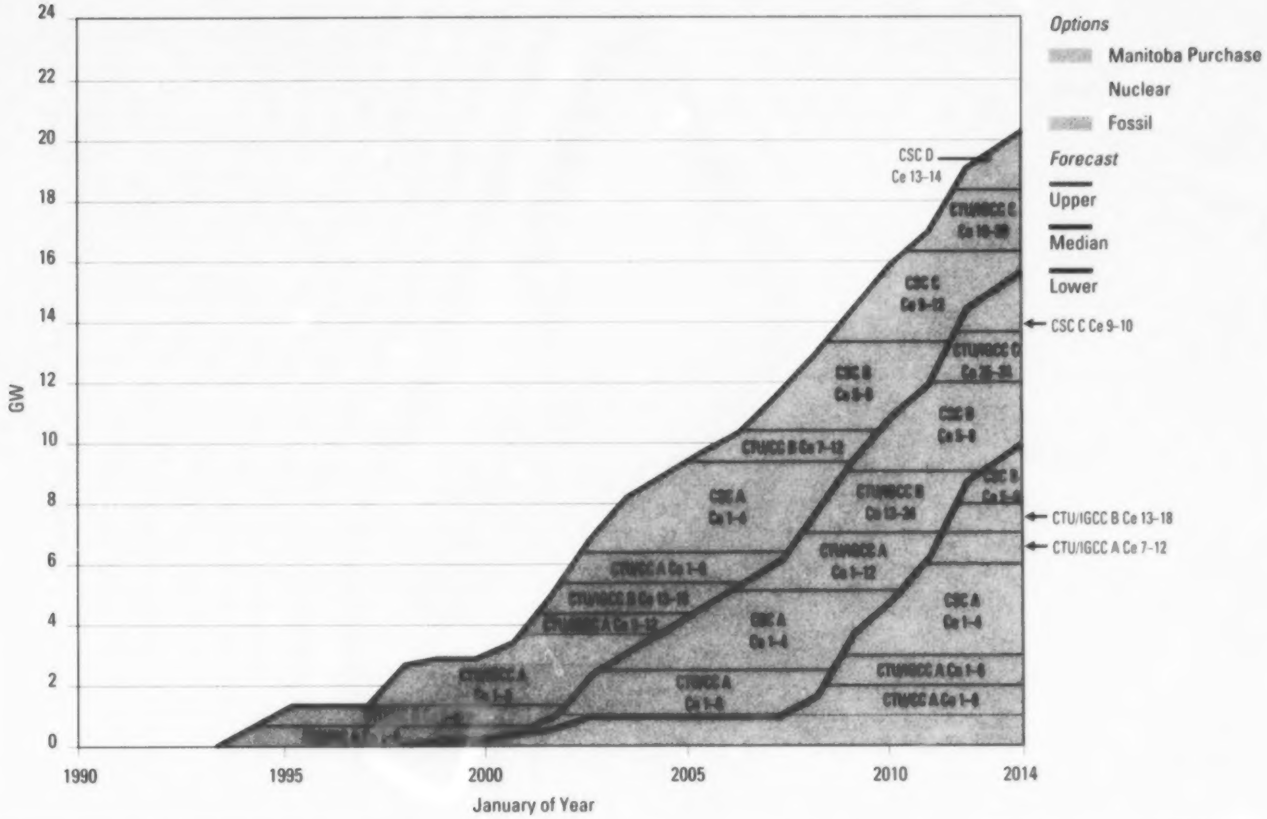
CTU/G	**a general term covering all CTUs;**
CTU/NC	**describes those CTUs with no provision for conversion;**
CTU/CC	**describes those CTUs convertible to CCs;**
CTU/IGCC	**describes those CTUs convertible to CC and IGCC units.**

Each Case requires differing numbers of generating units and stations. It is necessary at times to describe the number of stations required and the number, timing and capacity of the generating units at any station.

This will be done as follows:

- **Letters indicate the order in which stations of a particular option are employed, i.e., CANDU A is the first station, CANDU B is the second station.**
- **The units in stations of a particular option are numbered consecutively, i.e., CANDU A 1–4, CANDU B 5–8, CANDU C 9–10.**
- **For fossil options, the symbol Ce is introduced before the unit numbers. Ce means Capacity Equivalent, i.e., CTU/NC A Ce 1–4 is the first CTU/NC station, with four150 MW units, or different size units equivalent to 600 MW capacity.**

Figure 15–12 **New Major Supply** Case 26



mitted by lead times, and in later years they are advanced to reduce cost. CTUs at new stations are advanced more than CSC Coal units because of their shorter lead times. The remaining requirement is met with very short lead time CTU/NCs on existing stations. This Case requires, by 2014, 14 CSC coal units at four stations, eight CTU/NCs at two stations, 12 CTU/CCs at two stations, and 30 CTU/IGCCs at three stations.

Under the lower forecast, requirements are met with fewer and later CSC coal units and CTUs. The Manitoba Purchase is not delayed, because contract commitments have been made. This Case requires by 2014 six CSC Coal units at two stations, six CTU/CCs at one station, and 18 CTU/IGCCs at two stations.

Figure 15–13 provides the in-service date of each unit.

Lower Forecast

				Capacity Added By Year End (MW)									
Option	**Station**	**Units**	**Capacity (GW)**	**1990**	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**	**1998**	**1999**
Manitoba Purchase			1.000									200	
CTU/CC	A	1–6	1.008										
CTU/IGCC	A	1–12	2.016										
CSC Coal	A	1–4	2.964										
CSC Coal	B	5–6	1.482										
CTU/IGCC	B	13–18	1.008										
		Total (GW)	9.478										

Median Forecast

				Capacity Added By Year End (MW)									
Option	**Station**	**Units**	**Capacity (GW)**	**1990**	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**	**1998**	**1999**
Manitoba Purchase			1.000									200	
CTU/CC	A	1–6	1.008										
CTU/IGCC	A	1–12	2.016										
CSC Coal	A	1–4	2.964										
CTU/IGCC	B	13–24	2.016										
CSC Coal	B	5–8	2.964										
CTU/IGCC	C	25–34	1.680										
CSC Coal	C	9–10	1.482										
		Total (GW)	15.130										

Upper Forecast

				Capacity Added By Year End (MW)									
Option	**Station**	**Units**	**Capacity (GW)**	**1990**	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**	**1998**	**1999**
Manitoba Purchase			1.000									200	
CTU/NC	A	1–4	0.672				672						
CTU/NC	B	5–8	0.672					672					
CTU/IGCC	A	1–12	2.016								1344		
CTU/IGCC	B	13–18	1.008										
CTU/CC	A	1–6	1.008										
CSC Coal	A	1–4	2.964										
CTU/CC	B	5–12	1.008										
CTU/IGCC	C	19–30	2.016										
CSC Coal	B	5–8	2.964										
CSC Coal	C	9–12	2.964										
CSC Coal	D	13–14	1.482										
		Total (GW)	19.774										

[illegible]

Lower Forecast **Capacity Added By Year End (MW)**

2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
200	200	400											
								672	336				
									1008	336	672		
									741	741	741	741	
												741	741
												1008	

Median Forecast **Capacity Added By Year End (MW)**

2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
200	200	400											
	336	672											
		336					672	1008					
			741	741	741	741							
								672	1008	336			
									741	741	741	741	
										336	336	1008	
												741	741

Upper Forecast **Capacity Added By Year End (MW)**

2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
200	200	400											
336	336												
	1008												
		672	336										
		741	741	741	741								
			336			672							
							336				336	1344	
							741	741	741	741			
								741	741	741	741		
												741	741

Case 23

In this Case, more than 85% of new capacity under each load forecast condition consists of purchases and base load nuclear generation. The remaining is peaking fossil generation. Existing fossil stations are given a peaking role. Some fossil peaking generation is added, mostly under the upper load forecast. Figure 15–14 summarizes capacity additions by 2014.

The approximate timing of capacity additions over the planning period is shown in Figure 15–15.

Under the median load forecast nuclear generation eliminates the need for new peaking fossil and minimizes the use of existing fossil generation. In-service dates of nuclear units are scheduled to meet all requirements for new capacity, both base load requirements and some intermediate requirements. Existing fossil moves toward the peaking role and no new peaking generation is required. In total, by 2014, 16 CANDU units at four stations are required.

Under the upper load forecast, CTUs are added in the early years both at existing stations and at a new station. Additional nuclear units are added in later years. This Case requires, by 2014, 18 CANDU units at five stations, eight CTU/NCs at two stations, and eight CTU/IGCCs at one station.

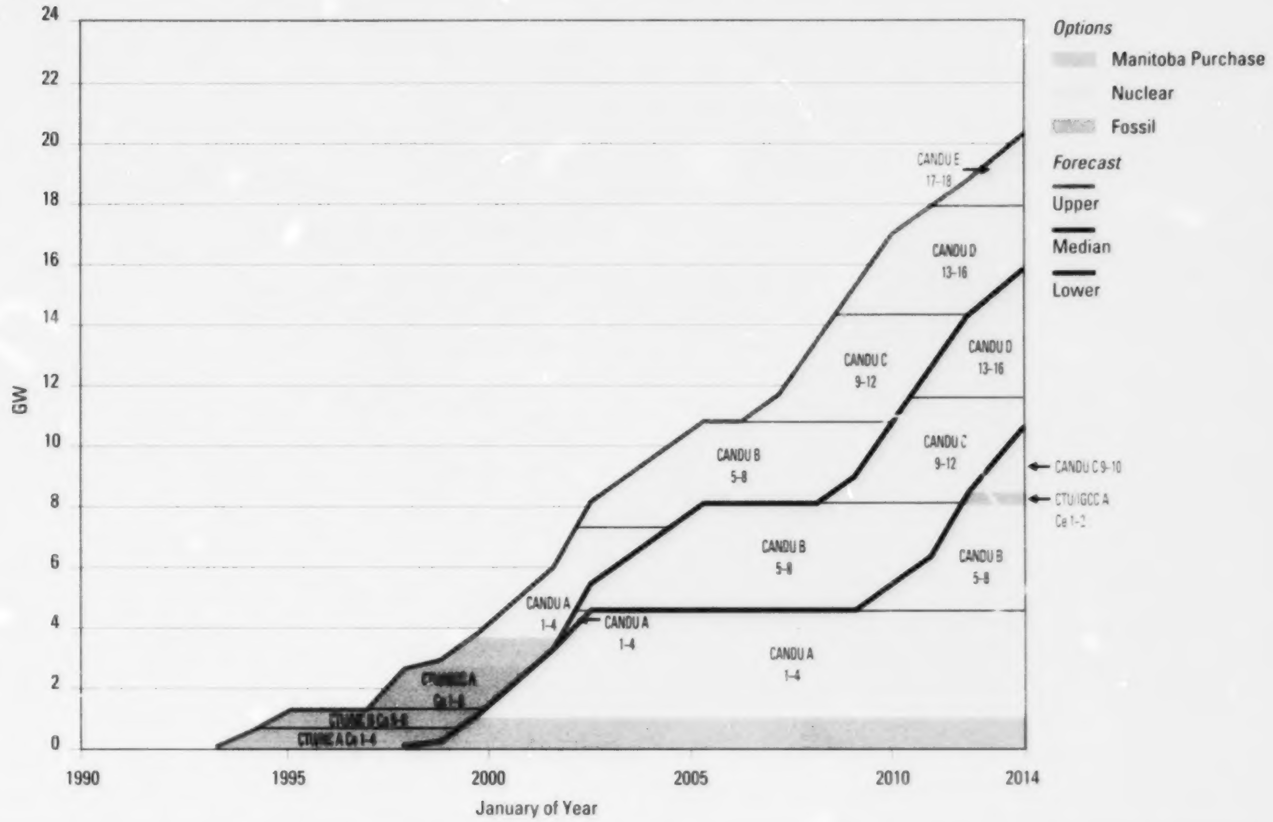
Under the lower load forecast, fewer nuclear units are required. This Case requires, by 2014, ten CANDU units at three stations, and two CTU/IGCCs at one station.

Figure 15–16 provides the in-service date of each unit.

[illegible]

	Capacity (GW)		
	Lower	Median	Upper
Major Supply Option	**Forecast**	**Forecast**	**Forecast**
Utility Purchase	1.0	1.0	1.0
CANDU	8.8	14.1	15.9
CTU/NC	0	0	1.3
CTU/CC	0	0	0
CTU/IGCC	0.3	0	1.3
Total	10.1	15.1	19.5

Figure 15–15 **New Major Supply** Case 23



Lower Forecast				Capacity Added By Year End (MW)									
Option	Station	Units	Capacity (GW)	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
Manitoba Purchase			1.000									200	
CANDU	A	1–4	3.524										881
CANDU	B	5–8	3.524										
CANDU	C	9–10	1.762										
CTU/IGCC	A	1–2	0.336										
		Total (GW)	10.146										

Median Forecast				Capacity Added By Year End (MW)									
Option	Station	Units	Capacity (GW)	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
Manitoba Purchase			1.000									200	
CANDU	A	1–4	3.524										881
CANDU	B	5–8	3.524										
CANDU	C	9–12	3.524										
CANDU	D	13–16	3.524										
		Total (GW)	15.096										

Upper Forecast				Capacity Added By Year End (MW)									
Option	Station	Units	Capacity (GW)	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
Manitoba Purchase			1.000									200	
CTU/NC	A	1–4	0.672				672						
CTU/NC	B	5–8	0.672					672					
CTU/IGCC	A	1–8	1.344								1344		
CANDU	A	1–4	3.524										881
CANDU	B	5–8	3.524										
CANDU	C	9–12	3.524										
CANDU	D	13–16	3.524										
CANDU	E	17–18	1.762										
		Total (GW)	19.546										

Lower Forecast

Capacity Added By Year End (MW)

2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
200	200	400											
881	881	881											
									881	881	881	881	
											881	881	
											336		

Median Forecast

Capacity Added By Year End (MW)

2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
200	200	400											
881	881	881											
		881	881	881	881								
									881	881	881	881	
										881	881	881	881

Upper Forecast

Capacity Added By Year End (MW)

2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
200	200	400											
881	881	881											
		881	881	881	881								
							881	881	881	881			
								881	881	881	881		
												881	881

Case 24

This Case is between Case 15 and Case 26. All peaking, all intermediate and part of the base load requirements are met by fossil generation.

Under the median load forecast, base load requirements are met, in turn, by CANDU A, CSC A, and CANDU B. Existing and new fossil generation meet intermediate and peak requirements. This Case requires, by 2014, four CSC coal units at one station, six CANDU units at two stations, six CTU/CCs at one station, and 30 CTU/IGCCs at three stations by 2014.

Under the upper load forecast, the base load requirements are met, in turn, by CANDU A, CSC A, CANDU B, and two units in CANDU C. Peaking requirements, by 2014, are met by eight CTU/NCs at two stations, ten CTU/CCs at two stations, and 24 CTU/IGCCs at three stations.

Under the lower load forecast, base load requirements are met by CANDU A followed by two units in CSC A. Peaking requirements, by 2014, are met by six CTU/CCs at one station, and 14 CTU/IGCCs at two stations.

An alternative variation of Case 24 was analyzed. It featured a CSC coal station as the first base load station. The variant with a CANDU station first is favoured because it maintains CANDU capability in Canada.

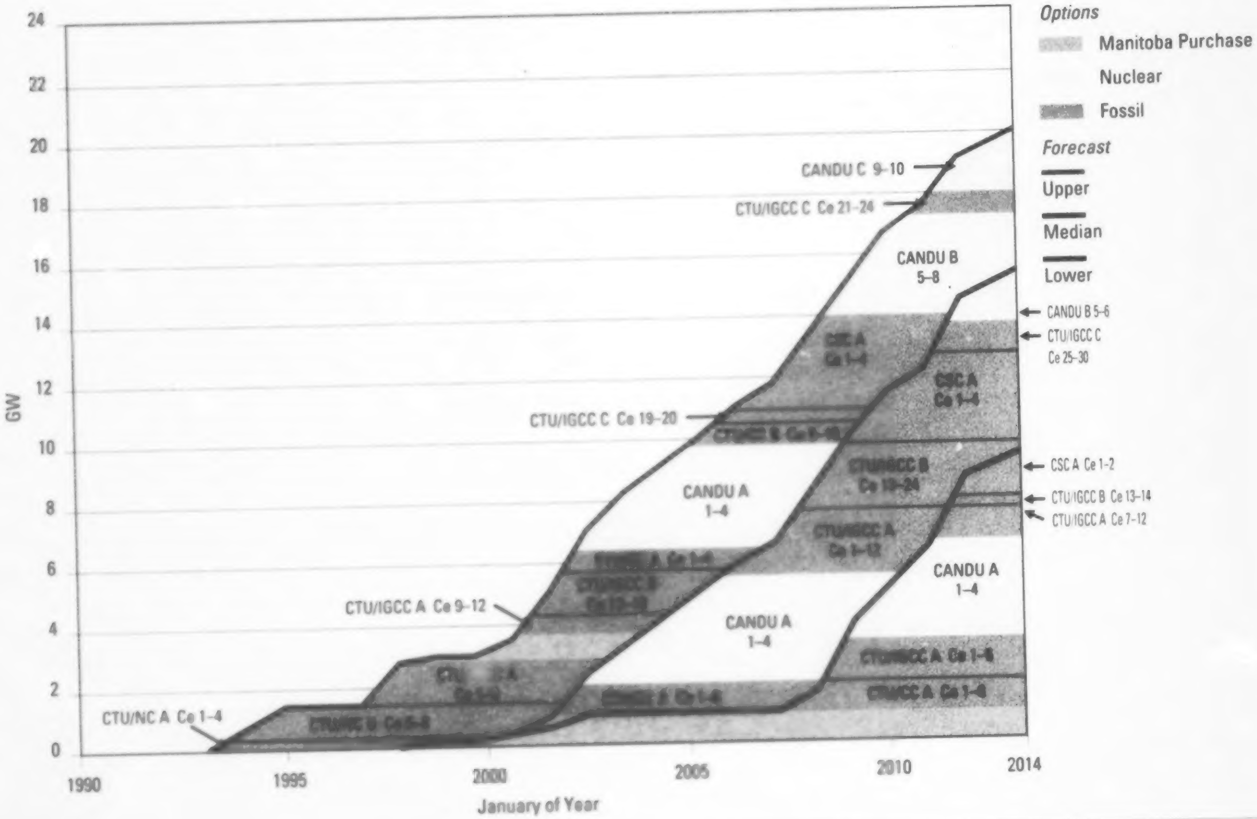
Figure 15-17 summarizes the capacity additions by the end of 2014.

The approximate timing of capacity additions over the planning period is shown in Figure 15-18.

Figure 15-19 provides the in-service date of each unit.

	Capacity (GW)		
	Lower	Median	Upper
Major Supply Option	Forecast	Forecast	Forecast
Utility Purchase	1.0	1.0	1.0
CSC – Coal	1.5	3.0	3.0
CANDU	3.5	5.3	8.8
CTU/NC	0	0	1.3
CTU/CC	1.0	1.0	1.7
CTU/IGCC	2.4	5.0	4.0
Total	9.4	15.3	19.8

Figure 15–18 **New Major Supply** Case 24



Lower Forecast

Option	Station	Units	Capacity (GW)	Capacity Added By Year End (MW)									
				1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
Manitoba Purchase			1.000									200	
CTU/CC	A	1–6	1.008										
CTU/IGCC	A	1–12	2.016										
CANDU	A	1–4	3.524										
CSC Coal	A	1–2	1.482										
CTU/IGCC	B	13–14	0.336										
		Total (GW)	9.366										

Median Forecast

Option	Station	Units	Capacity (GW)	Capacity Added By Year End (MW)									
				1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
Manitoba Purchase			1.000									200	
CTU/CC	A	1–6	1.008										
CTU/IGCC	A	1–12	2.016										
CANDU	A	1–4	3.524										
CTU/IGCC	B	13–24	2.016										
CSC Coal	A	1–4	2.964										
CTU/IGCC	C	25–30	1.008										
CANDU	B	5–6	1.762										
		Total (GW)	15.298										

Upper Forecast

Option	Station	Units	Capacity (GW)	Capacity Added By Year End (MW)									
				1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
Manitoba Purchase			1.000									200	
CTU/NC	A	1–4	0.672				672						
CTU/NC	B	5–8	0.672					672					
CTU/IGCC	A	1–12	2.016								1344		
CTU/IGCC	B	13–18	1.008										
CTU/CC	A	1–4	0.672										
CANDU	A	1–4	3.524										
CTU/CC	B	5–10	1.008										
CTU/IGCC	C	19–24	1.008										
CSC Coal	A	1–4	2.964										
CANDU	B	5–8	3.524										
CANDU	C	9–10	1.762										
		Total (GW)	19.830										

Lower Forecast **Capacity Added By Year End (MW)**

2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
200	200	400											
								672	336				
									1008	336	336	336	
									881	881	881	881	
												741	741
												336	

Median Forecast **Capacity Added By Year End (MW)**

2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
200	200	400											
	336	672											
		336					672	1008					
			881	881	881	881							
								672	1008	336			
									741	741	741	741	
										336		672	
												881	881

Upper Forecast **Capacity Added By Year End (MW)**

2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
200	200	400											
336	336												
	1008												
		672											
		881	881	881	881								
			336			672							
						336						672	
							741	741	741	741			
								881	881	881	881		
												881	881

Case 22

This Case is between Case 15 and Case 23.

Under the median load forecast, nuclear units are scheduled to reduce the need for new fossil generation until later in the period. This Case requires, by 2014, 12 CANDU units at three stations, six CTU/CCs at one station, and 16 CTU/IGCCs at two stations.

Under the upper load forecast, requirements are met initially by CTU/NCs on existing sites, and then by CTU/IGCCs. Nuclear units provide base load generation as lead time permits. This Case requires, by 2014, 15 CANDU units at four stations, eight CTU/NCs at two stations, ten CTU/CCs at two stations, and 16 CTU/IGCCs at two stations.

For lower load forecast, eight CANDU units at two stations and ten CTU/IGCCs at one station are required by 2014.

Figure 15–20 summarizes total capacity additions by 2014.

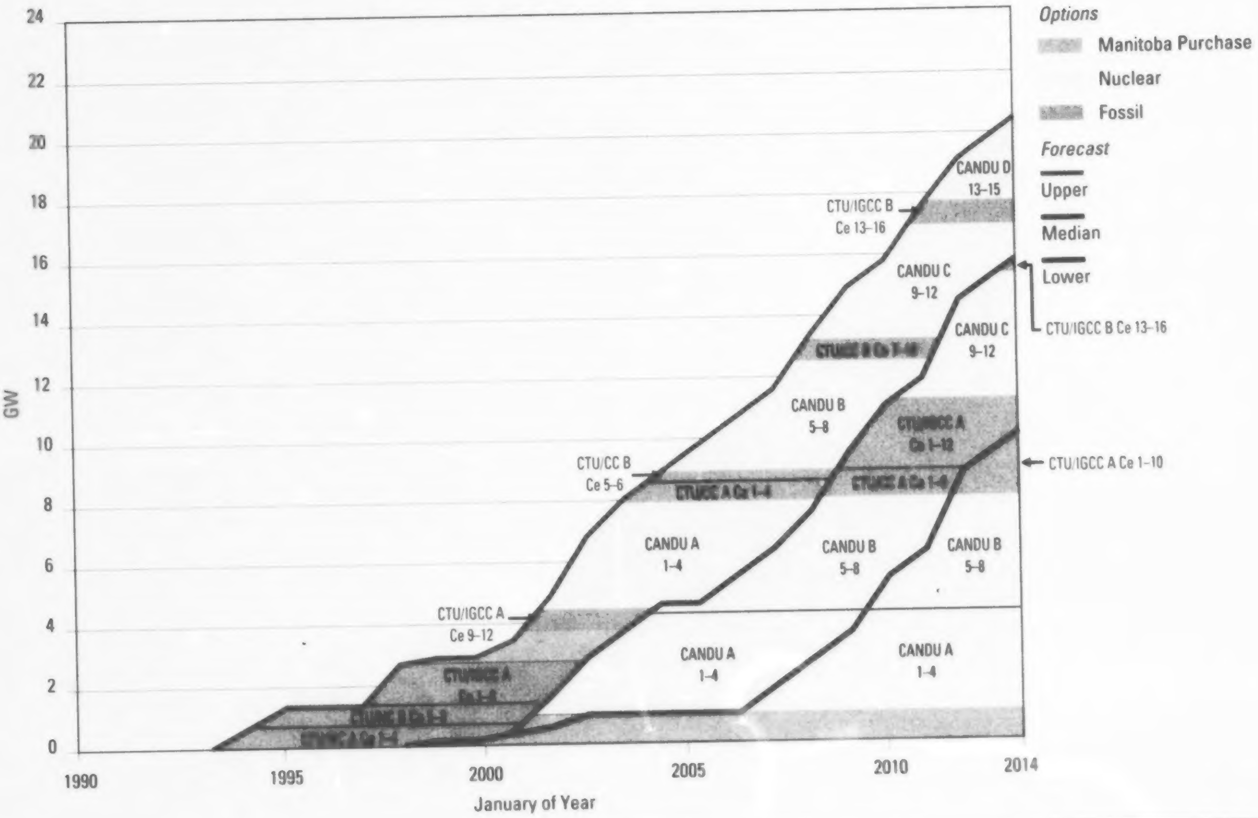
The approximate timing of capacity additions over the planning period is shown in Figure 15–21.

Figure 15–22 provides in-service dates of each unit.

[illegible]

	Capacity (GW)		
Major Supply Option	**Lower Forecast**	**Median Forecast**	**Upper Forecast**
Utility Purchase	1.0	1.0	1.0
CANDU	7.0	10.6	13.2
CTU/NC	0	0	1.3
CTU/CC	0	1.0	1.7
CTU/IGCC	1.7	2.7	2.7
Total	9.7	15.3	19.9

Figure 15–21 **New Major Supply** Case 22



Lower Forecast

				Capacity Added By Year End (MW)									
Option	**Station**	**Units**	**Capacity (GW)**	**1990**	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**	**1998**	**1999**
Manitoba Purchase			1.000									200	
CANDU	A	1–4	3.524										
CANDU	B	5–8	3.524										
CTU/IGCC	A	1–10	1.680										
		Total (GW)	9.728										

Median Forecast

				Capacity Added By Year End (MW)									
Option	**Station**	**Units**	**Capacity (GW)**	**1990**	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**	**1998**	**1999**
Manitoba Purchase			1.000									200	
CANDU	A	1–4	3.524										
CANDU	B	5–8	3.524										
CTU/CC	A	1–6	1.008										
CTU/IGCC	A	1–12	2.016										
CANDU	C	9–12	3.524										
CTU/IGCC	B	13–16	0.672										
		Total (GW)	15.268										

Upper Forecast

				Capacity Added By Year End (MW)									
Option	**Station**	**Units**	**Capacity (GW)**	**1990**	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**	**1998**	**1999**
Manitoba Purchase			1.000									200	
CTU/NC	A	1–4	0.672				672						
CTU/NC	B	5–8	0.672					672					
CTU/IGCC	A	1–12	2.016								1344		
CANDU	A	1–4	3.524										
CTU/CC	A	1–4	0.672										
CTU/CC	B	5–10	1.008										
CANDU	B	5–8	3.524										
CANDU	C	9–12	3.524										
CTU/IGCC	B	13–16	0.672										
CANDU	D	13–15	2.643										
		Total (GW)	19.927										

Lower Forecast

Capacity Added By Year End (MW)

2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
200	200	400											
							881	881	881	881			
										881	881	881	881
												1680	

Median Forecast

Capacity Added By Year End (MW)

2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
200	200	400											
	881	881	881	881									
						881	881	881	881				
								336	672				
									336	672		1008	
										881	881	881	881
												672	

Upper Forecast

Capacity Added By Year End (MW)

2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
200	200	400											
336	336												
	881	881	881	881									
		672											
			336						672				
					881	881	881	881					
								881	881	881	881		
												672	
											881	881	881

Capacity Contribution

This section compares the capacity contributed by the generating options in each of the five Cases under three load forecasts, Figure 15–23.

The figure shows that the Cases are very different in terms of the capacity contribution from different options. The CANDU contribution varies from zero under all load forecasts in Case 26 to 15.9 GW under upper load forecast in Case 23. The CSC coal varies from zero under all load forecasts in Case 15 to 10.4 GW in Case 26 under the upper forecast. CTU/G varies from zero under median forecast in Case 23 to 8.4 GW under upper forecast in Case 26.

In Case 15, under median forecast, the capacity contributions are: CANDU – 8.8 GW, CTU/G – 5.4 GW, and Manitoba Purchase – 1.0 GW.

Figure 15–24 compares the number of stations and units for each option in the five Cases under three load forecasts.

Given the large variation in generation capacity, there are also large variations in the number of stations and units.

The CTU/G varies from zero to 50 units, the CANDU from zero to 18 units.

Figure 15–23 Comparison of Major Capacity Additions by 2014 (GW)

	Options Manitoba Purchase	CANDU	CSC Coal	CTU/G	Total
Lower Load Forecast					
Case 23	1.0	8.8	0.0	0.3	10.1
Case 22	1.0	7.0	0.0	1.7	9.7
Case 15	1.0	5.3	0.0	3.3	9.6
Case 24	1.0	3.5	1.5	3.4	9.4
Case 26	1.0	0.0	4.5	4.0	9.5
Median Load Forecast					
Case 23	1.0	14.1	0.0	0.0	15.1
Case 22	1.0	10.6	0.0	3.7	15.3
Case 15	1.0	8.8	0.0	5.4	15.2
Case 24	1.0	5.3	3.0	6.0	15.3
Case 26	1.0	0.0	7.4	6.7	15.1
Upper Load Forecast					
Case 23	1.0	15.9	0.0	2.6	19.5
Case 22	1.0	13.2	0.0	5.7	19.9
Case 15	1.0	12.3	0.0	6.4	19.7
Case 24	1.0	8.8	3.0	7.0	19.8
Case 26	1.0	0.0	10.4	8.4	19.8

Energy Production

The simulation of energy production includes not only a Major Supply Plan, but the existing system and the Demand Management, Hydraulic and NUG Plans. This is because the addition of new demand/supply options affects the deployment of the existing system. Also, acid gas controls are deployed system-wide.

Ontario Hydro designs its system to meet the needs of its customers in Ontario and, when applicable, contractual commitments to other utilities.

Non-firm sales to other utilities are excluded from energy production figures. These sales, which have been in the one to ten TWh per year range, will likely continue when there is mutual benefit and an opportunity for Hydro to generate net revenue to reduce costs to Ontario customers.

Summaries of energy production, using five-year averages, for all three load forecasts are shown in Figures 15–25, 15–26 and 15–27.

Energy production from hydraulic generation and utility and non-utility purchases are common to all Cases.

Hydraulic generation rises from about 35 to 40 TWh per year over the plan period for all Cases and under all load paths.

Under all load forecast paths, energy from the Manitoba Purchase begins in 1998, rises to about 7 TWh per year by 2003, and continues at that level to the end of the plan period.

Purchases from NUGs grow from small values to nearly 11 TWh per year by the end of the plan period under median load forecast;

Figure 15-24 Comparison of New Units and Stations Required by 2014

	Units			Stations		
	CANDU	**CSC Coal**	**CTU/G**	**CANDU**	**CSC Coal**	**CTU/G**
Lower Load Forecast						
Case 23	10	0	2	3	0	1
Case 22	8	0	10	2	0	1
Case 15	6	0	20	2	0	3
Case 24	4	2	20	1	1	3
Case 26	0	6	24	0	2	3
Median Load Forecast						
Case 23	16	0	0	4	0	0
Case 22	12	0	32	3	0	3
Case 15	10	0	32	3	0	4
Case 24	6	4	36	2	1	4
Case 26	0	10	40	0	3	4
Upper Load Forecast						
Case 23	18	0	16	5	0	3
Case 22	15	0	34	4	0	6
Case 15	14	0	38	4	0	7
Case 24	10	4	42	3	1	7
Case 26	0	14	50	0	4	7

** For fossil stations, different numbers of units, providing equivalent capacity may be used*

Biological surveys are done to determine environmental impacts of electricity generating facilities.

they grow to about 6 TWh per year under lower load forecast; and to about 12 TWh per year under upper load forecast. Utility and non-utility purchases are combined in the figures.

Nuclear and fossil energy production vary significantly between Cases.

Under lower load forecast, the differences between Cases are diminished, because there is less need for new generation. All Cases have very low fossil energy production in the late 1990s.

Under median load forecast, nuclear energy production at the end of the plan period ranges from about 90 TWh per year in Case 26 to 150 TWh per year in Case 23. Case 26 has fossil energy production as high as 65 TWh per year, approaching the same level as nuclear production. Case 23 reduces fossil energy production to less than five TWh per year.

Under upper load forecast, fossil energy production is generally higher than for the median path. Most of the increased energy is produced by intermediate fossil stations. In Case 26, fossil energy production reaches 90 TWh per year by 2014. Nuclear generation ranges from close to 90 TWh per year in Case 26 to 170 TWh per year in Case 23 by 2014.

Emission Controls On Existing Fossil Units

All new fossil generation added to the system will have emission controls. The existing fossil units will also require emission controls. Under lower load forecast, all Cases required retrofit of SO_2 scrubbers on two existing coal-fueled

Figure 15–25 **Average Annual Energy Production – Lower Forecast**

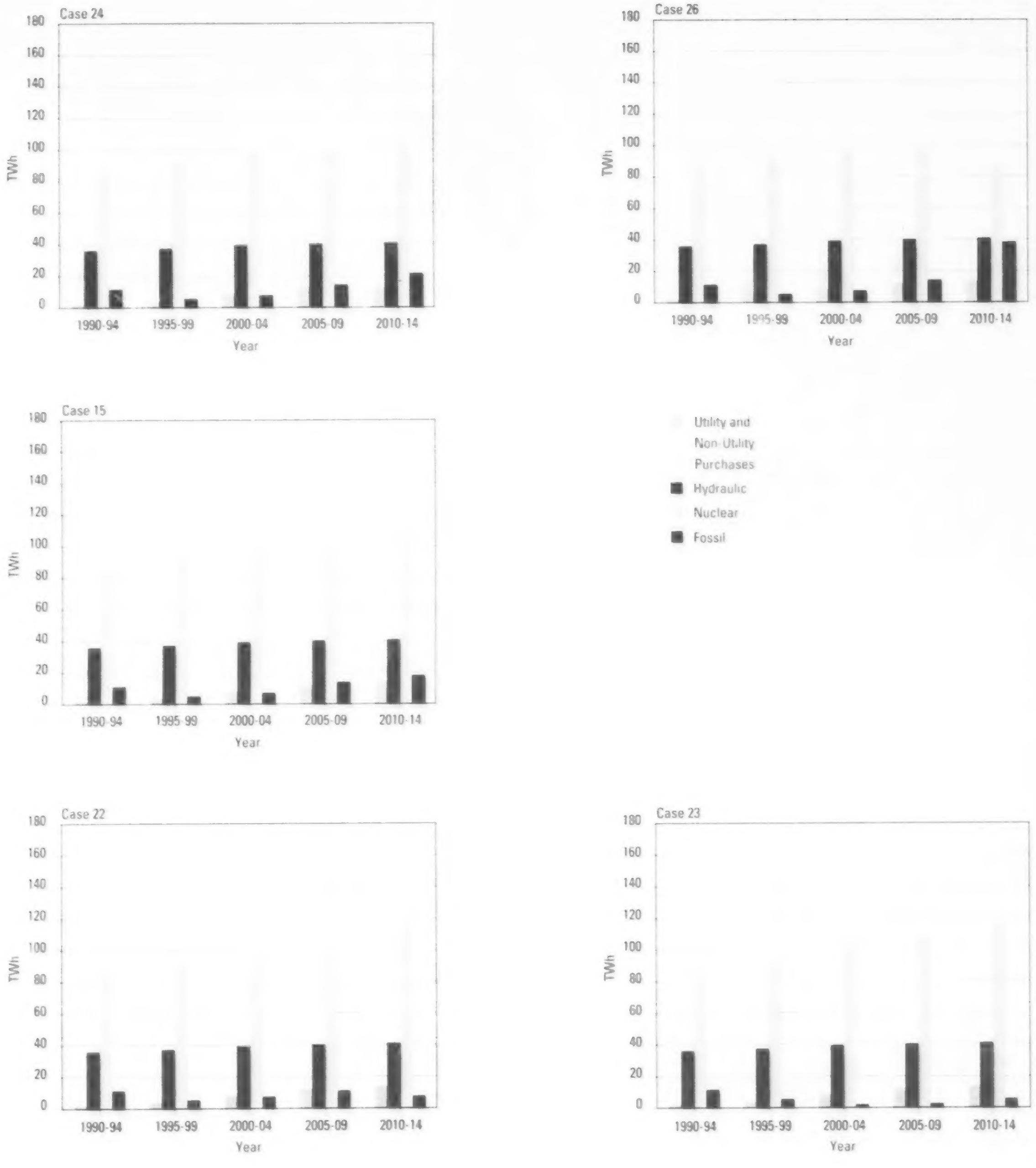


Figure 15–26 **Average Annual Energy Production – Median Forecast**

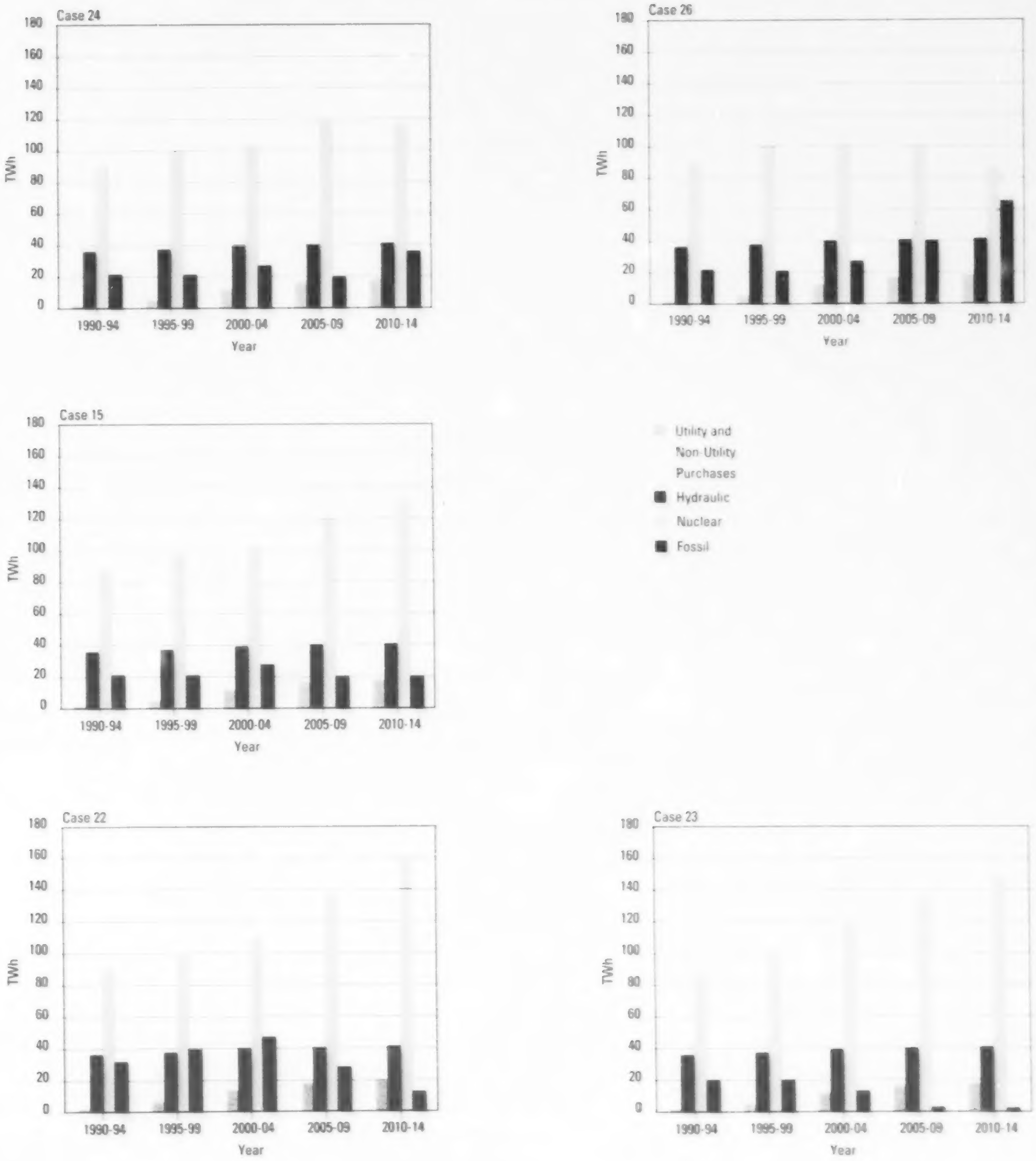
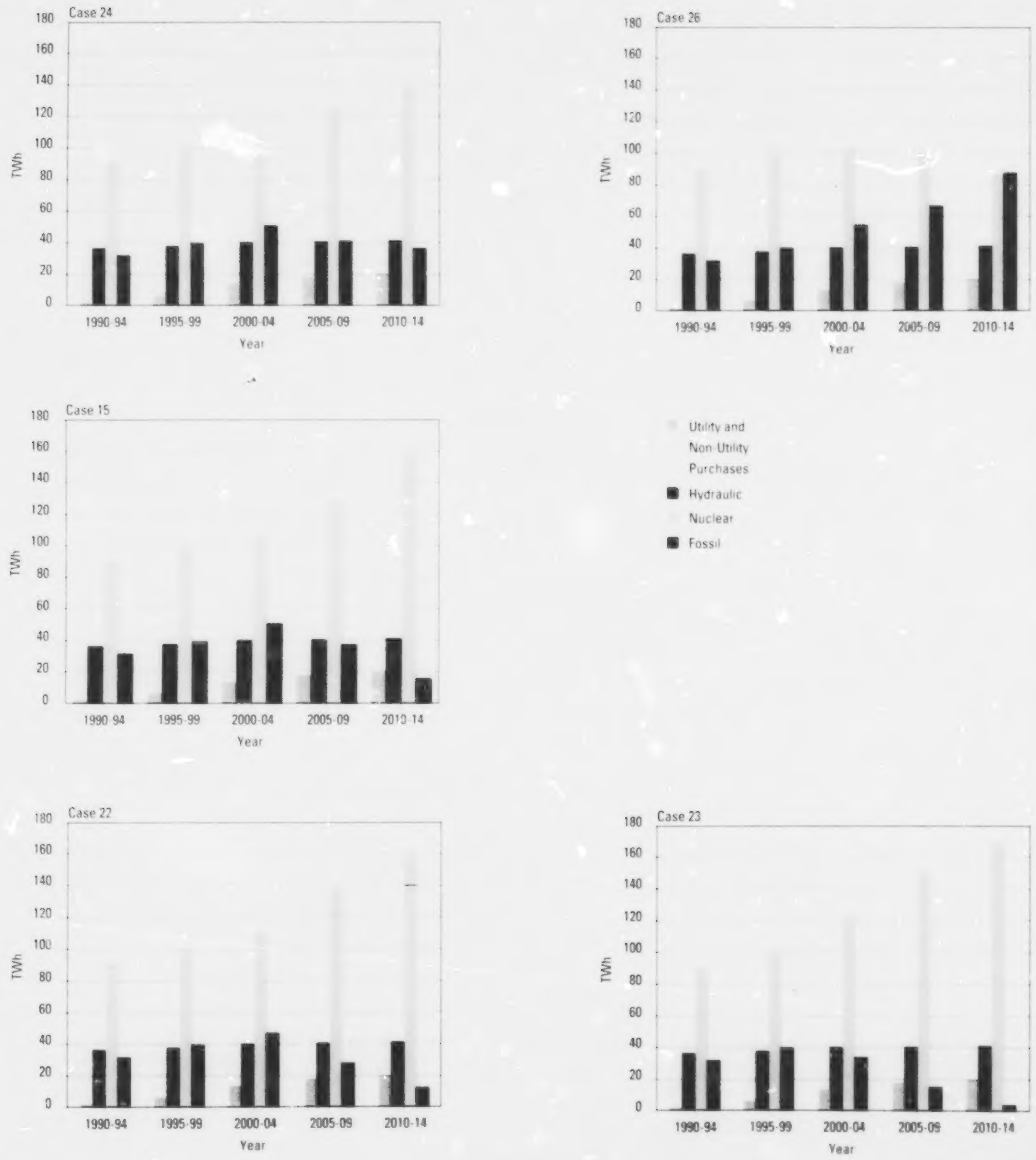
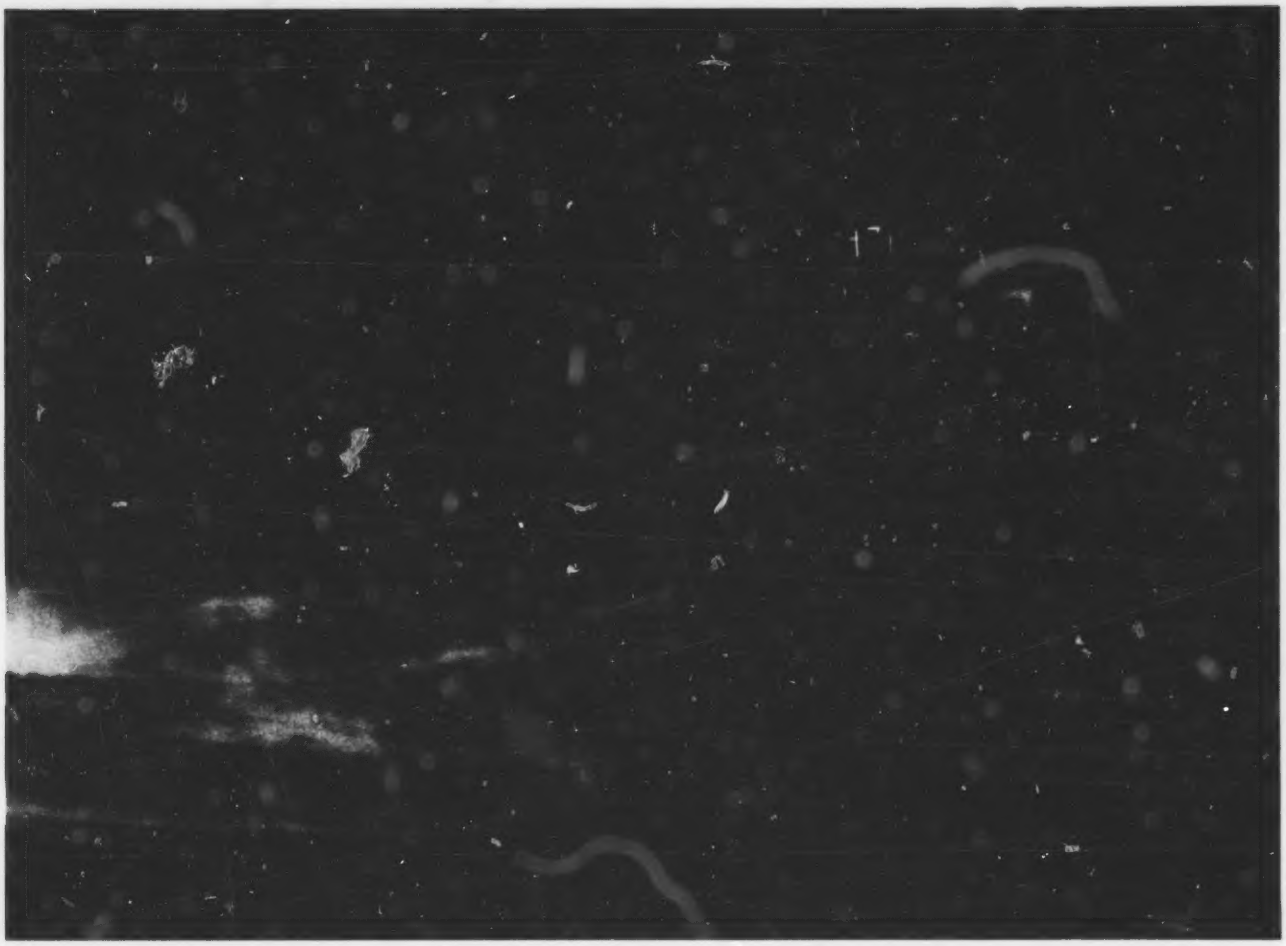


Figure 15–27 **Average Annual Energy Production – Upper Forecast**





Existing coal-fueled stations are used to meet peak and intermediate demands.

units and the retrofit of Combustion Process Modifications (CPMs) on four existing units for NO$_X$ control. Under the median forecast, four SO$_2$ scrubbers and eight sets of CPMs are required. Under the upper forecast, twelve scrubbers and eight sets of CPMs are required.

Possible candidate sites for new major supply options are discussed in Chapter 14. Illustrative sites for each Case are selected from the list of possible sites so that the cost analysis described later in this chapter includes siting and transmission costs. The set of illustrative sites for each Case represents a feasible choice and meets the planning requirement for a geographic balance between electricity demand and supply, Figure 15–28.

In general, the Cases require sites for CANDU stations, CSC coal stations, CTUs convertible into IGCCs, CTUs convertible into CC units, and CTU/NCs without further development options.

			Case 23		Case 22		Case 15		Case 24		Case 26
Site	Load Forcast Condition	Option	In-Service	Option	In-Service	Option	In-Service	Option	In-Service	Option	In-Service
Darlington B	Lower	CANDU A	1999	CANDU A	2007	CANDU A	2009	CANDU A	2009		
	Median	CANDU A	1999	CANDU A	2001	CANDU A	2003	CANDU A	2003		
	Upper	CANDU A	1999	CANDU A	2001	CANDU A	2002	CANDU A	2002		
Hearn	Lower					CTU/CC A	2008	CTU/CC A	2008	CTU/CC A	2008
	Median			CTU/CC A	2008	CTU/CC A	2001	CTU/CC A	2001	CTU/CC A	2001
	Upper			CTU/CC B	2003	CTU/CC B	2002	CTU/CC B	2003	CTU/CC B	2003
Keith	Lower										
	Median										
	Upper			CTU/CC A	2002	CTU/CC A	2001	CTU/CC A	2002	CTU/CC A	2002
Lakeview	Lower	CTU/IGCC A	2012	CTU/IGCC A	2012	CTU/IGCC B	2012	CTU/IGCC B	2012	CTU/IGCC B	2012
	Median			CTU/IGCC B	2012	CTU/IGCC B	2009	CTU/IGCC B	2008	CTU/IGCC B	2008
	Upper			CTU/IGCC B	2012	CTU/IGCC B	2012	CTU/IGCC C	2006	CTU/IGCC C	2007
Lambton	Lower										
	Median					CTU/IGCC C	2012	CTU/IGCC C	2010	CTU/IGCC C	2010
	Upper	CTU/NC A	1993	CTU/NC A	1993	CTU/NC A	1993	CTU/NC A	1993	CTU/NC A	1993
Lennox A	Lower										
	Median										
	Upper					CTU/NC C	2001				
Lennox B	Lower										
	Median										
	Upper							CTU/IGCC B	2001	CTU/IGCC B	2001
Nanticoke	Lower										
	Median										
	Upper	CTU/NC B	1994	CTU/NC B	1994	CTU/NC B	1994	CTU/NC B	1994	CTU/NC B	1994

			Case 23		Case 22		Case 15		Case 24		Case 26
Site	Load Forcast Condition	Option	In-Service	Option	In-Service	Option	In-Service	Option	In-Service	Option	In-Service
New Site 1	Lower	CANDU C	2012								
	Median	CANDU C	2009	CANDU C	2010	CANDU C	2012	CANDU B	2012	CSC Coal C	2012
	Upper	CANDU C	2007	CANDU C	2008	CANDU C	2008	CANDU B	2008	CSC Coal C	2008
New Site 2	Lower										
	Median	CANDU D	2010								
	Upper	CANDU D	2008	CANDU D	2011	CANDU D	2012	CANDU C	2012	CSC Coal D	2012
New Site 3	Lower										
	Median										
	Upper	CANDU E	2012								
North Channel	Lower	CANDU B	2010	CANDU B	2010	CANDU B	2012	CSC Coal A	2012	CSC Coal B	2012
	Median	CANDU B	2002	CANDU B	2006	CANDU B	2009	CSC Coal A	2009	CSC Coal B	2009
	Upper	CANDU B	2002	CANDU B	2005	CANDU B	2007	CSC Coal A	2007	CSC Coal B	2007
Wesleyville A	Lower					CTU/IGCC A	2009	CTU/IGCC A	2009	CTU/IGCC A	2009
	Median			CTU/IGCC A	2009	CTU/IGCC A	2002	CTU/IGCC A	2002	CTU/IGCC A	2002
	Upper	CTU/IGCC A	1997	CTU/IGCC A	1997	CTU/IGCC A	1997	CTU/IGCC A	1997	CTU/IGCC A	1997
Wesleyville B	Lower									CSC Coal A	2009
	Median									CSC Coal A	2003
	Upper									CSC Coal A	2002

Darlington B and North Channel are used as reference sites for CANDU stations. Wesleyville B is used as a reference site for a CSC coal station. In those Cases where North Channel is not used for a nuclear station, it is a reference site for a CSC coal station. Wesleyville could also be a site for a CANDU station. Wesleyville A and Lennox B are sites for CTU/IGCC. Lakeview and Lambton become CTU/IGCC sites once the existing generation is decommissioned. These stations begin as CTUs, but have provisions to develop into IGCC sites, if required.

Hearn and Keith are suitable sites for CTU/CC now and are capable of additional capacity if the existing generation is decommissioned.

Lennox A, Lambton, Nanticoke and Lakeview could accommodate CTU/NCs during the life of the existing station, if required to meet the upper load forecast.

Figure 15–28 shows an example of how illustrative sites could be used in each Case under all three load forecasts. An alternative siting sequence was also studied.

The number of sites required varies between Cases and between load forecasts (Figure 15–29). For the upper load forecast, eight to eleven sites would be used; for the median forecast, four to seven; for the lower forecast, three to five.

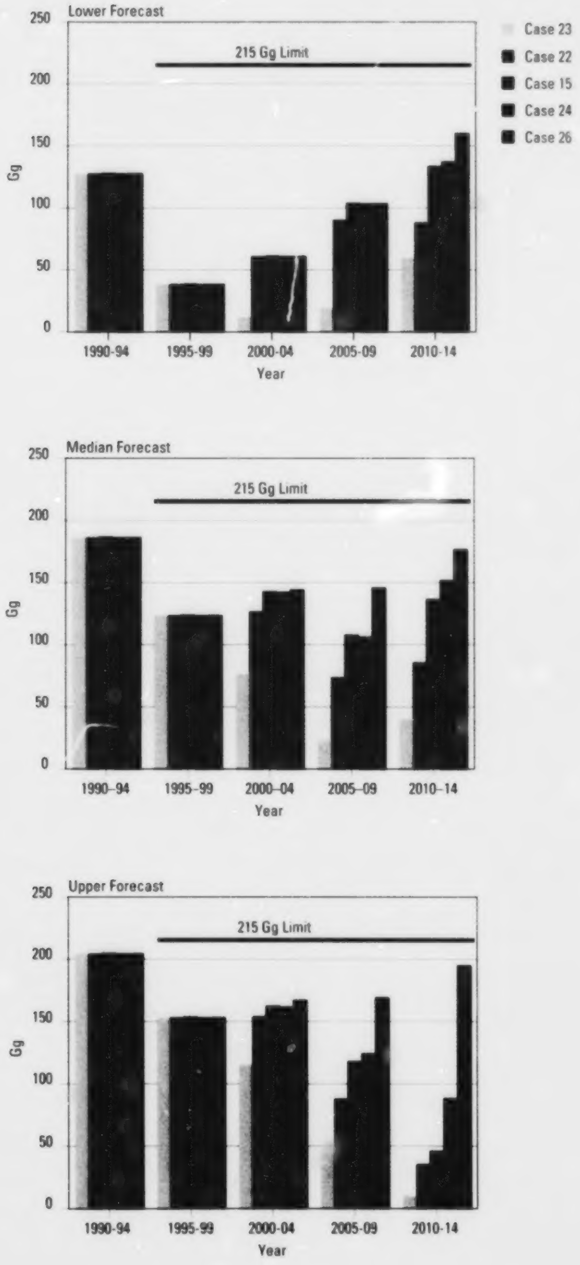
Need for New Sites

To meet base load requirements, all Cases require new sites to be identified in locations that maintain geographical balance between demand and generation. For the median forecast, two sites need to be identified in Cases 15, 22, 24 and 26; and three in Case 23.

Load Forecast	Case 23	Case 22	Case 15	Case 24	Case 26
Existing Sites Used					
Lower	2	2	4	4	4
Median	1	4	5	5	5
Upper	4	7	8	8	8
New Sites Used					
Lower	2	1	1	1	1
Median	3	2	2	2	2
Upper	4	3	3	3	3
Total Sites Used					
Lower	4	3	5	5	5
Median	4	6	7	7	7
Upper	8	10	11	11	11

Approvals requested in this application (see Chapter 19) include the requirement and rationale for the stations and sites in the Hydraulic Generation Plan, and the requirement and rationale for new fossil and nuclear generation. Locations to be considered for the various fossil and nuclear projects will include at least those sites shown in Figure 14–22. Approvals are also requested for the requirement and rationale for radial transmission to incorporate new generation to the existing and planned Bulk Transmission System. Subsequent project assessments will ensure that the proposed facilities are located and implemented in an environmentally acceptable manner, and with opportunities for community input. Project assessments will not duplicate or reconsider the planning issues determined by this application.

Figure 15–30 **Average Annual Acid Gas Emissions**



Alternatives exist within the existing identified sites. For example, in most Cases, Wesleyville B could be used as an alternative to Darlington B for a nuclear station east of Toronto. However, the existing identified alternatives are limited and new sites need to be identified in the early 1990s to provide additional alternatives to the existing and identified sites.

Chapter 14 identified transmission requirements to ensure that the cost analysis includes transmission costs.

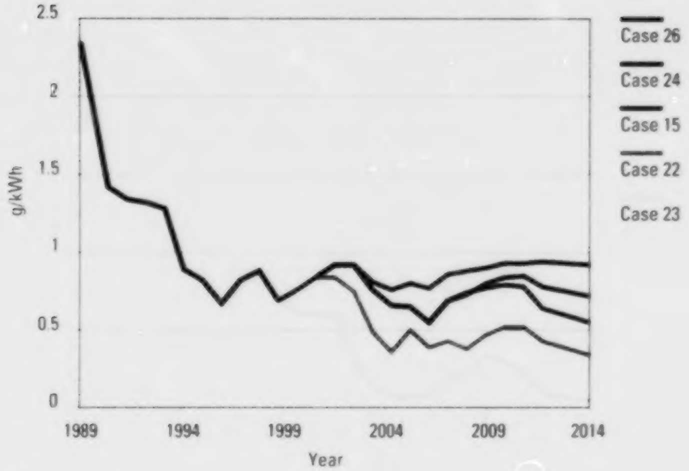
Generally, the amount required varies little between Cases for the same load forecast. The main difference between Cases for the same load forecast is in the order and timing of additions to the Bulk Transmission System. However, in some Cases, particularly under lower load, there are differences of up to 350 km in the total length of transmission requirements. The amount of transmission required increases with load.

This section compares the five Cases under a variety of topics derived from the planning criteria.

Safety Requirements And Standards And Public Safety Characteristics

All options in all Cases will be designed, built, operated and decommissioned in a manner that is consistent with Hydro's safety standards and meets or betters federal and provincial safety requirements.

Figure 15-31 **Trends in Acid Gas Emissions 1989–2014**



> *"Ontario Hydro reactors are being operated safely and at high standards of technical performance. No significant adverse impact has been detected in either the workforce or the public. The risk of accidents serious enough to affect the public adversely can never be zero, but it is very remote."*
>
> *– Dr. F.K. Hare, Commissioner of the Ontario Nuclear Safety Review*

The safety of nuclear stations is of particular concern to the public, and is of major importance to Hydro. The safety of Ontario Hydro's nuclear stations was reviewed in 1987–88 by Dr. F.K. Hare, Commissioner of the Ontario Nuclear Safety Review. The report concluded: "Ontario Hydro reactors are being operated safely and at high standards of technical performance. No significant adverse impact has been detected in either the workforce or the public. The risk of accidents serious enough to affect the public adversely can never be zero, but it is very remote."

Environmental Requirements, Standards And Characteristics – General

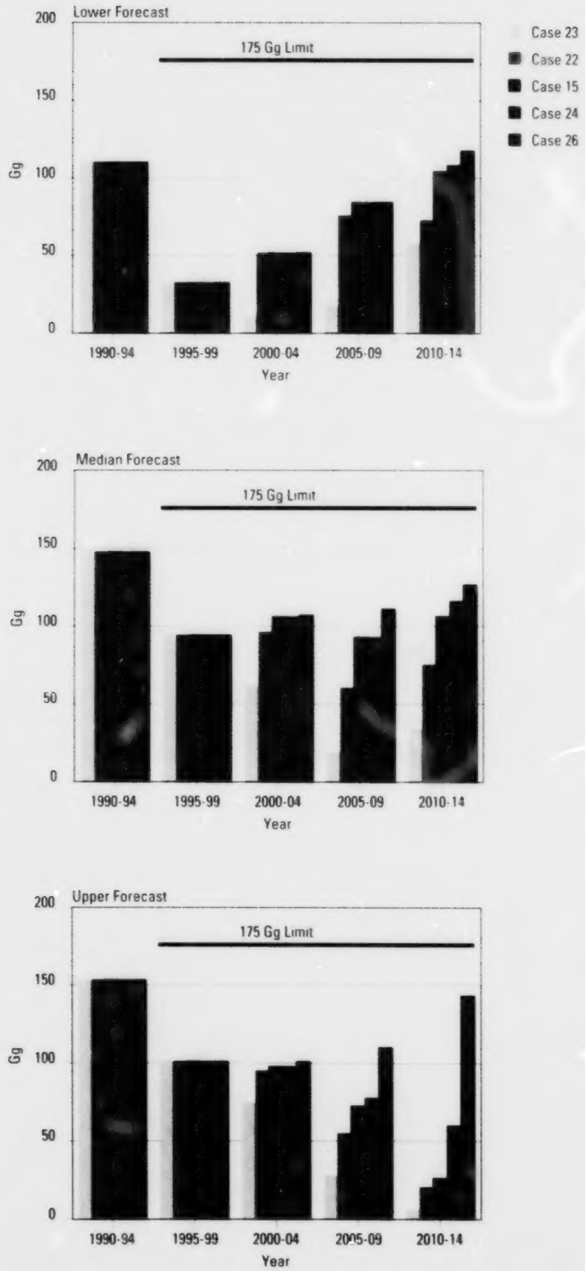
The natural environment effects of the Demand Management, Non-Utility Generation and Hydraulic Generation Plans are common to all Cases.

Potential effects on the natural environment of major supply options and related mitigation measures were considered in Chapter 14.

Some environmental effects are monitored on a system-wide basis and have significant impact on major supply plans.

Other natural environment effects are monitored and controlled at the station site. For example, radioactivity from nuclear facilities is controlled, by design and operation, to limit public radiation exposure to less than the regulatory limit set by the Atomic Energy Control Board. Results of monitoring are submitted to regulatory authorities. Station specific emissions are discussed in Chapter 14 and will be thoroughly examined during specific project approval.

Figure 15–32 **Average Annual SO_2 Emissions**



The following sections review the system-wide environmental effects of the five Cases; additional detail is in the Demand/Supply Environmental Analysis Report.

Environment – Acid Gas Emissions

Total acid gas emissions by Ontario Hydro are limited by regulation to 215 Gg per year, starting in 1994. These acid gas emissions include sulphur dioxide (SO_2) and nitrogen oxides (NO_x).

All Cases meet the total acid gas emission limit under all load forecasts.

However, there are major differences in emissions between Cases, starting in 2000.

Figure 15–30 shows, in five-year averages, the predicted acid gas emissions.

Trends in acid gas emissions, expressed in g/kWh of total Ontario Hydro generation, are shown in Figure 15–31. There is a drop in emission rates in all Cases, particularly Cases 22 and 23.

Environment – SO_2 Emissions

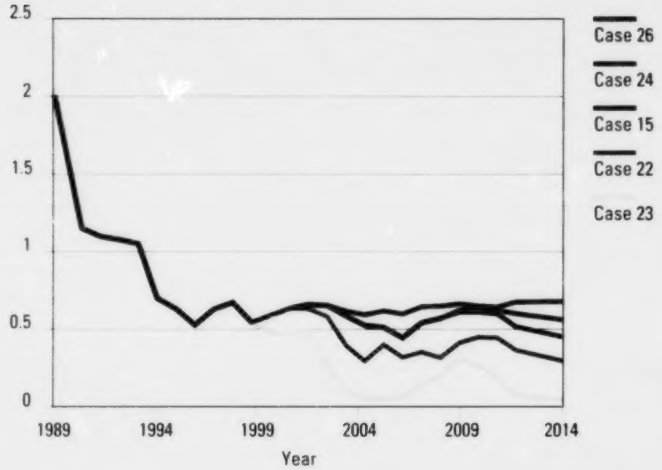
Along with limiting total acid gas emissions, the regulation also limits SO_2 to 175 Gg per year by 1994.

All Cases meet the SO_2 limit under all load forecast conditions.

However, there are large differences between Cases (Figure 15–32).

Trends in SO_2 emissions, expressed in g/kWh of total Ontario Hydro generation, are shown in Figure 15–33. There is a drop in emission rates, especially for Cases 22 and 23.

Figure 15–33 **Trends in SO2 Emissions 1989–2014**



Environment – NO_x Emissions

NO_x is limited in combination with SO_2 to a total of 215 Gg per year. However, it is anticipated that NO_x emissions in excess of about 60 Gg per year could become a public concern. Canada has signed an international protocol agreeing to keep NO_x emissions below 1987 levels. Hydro's 1987 NO_x emissions were 62 Gg.

Figure 15–34 shows that under upper load forecast, peak NO_x emissions in all Cases except Case 23 average about 60 to 70 Gg per year from 2000 to 2004.

Under median and lower load forecast, all Cases except Case 26 have NO_x emissions at or less than 40 Gg per year. From 2010 to 2014, emissions in Case 26 are about 50 Gg per year under median forecast.

Figure 15–34 **Average Annual NO_x Emissions**

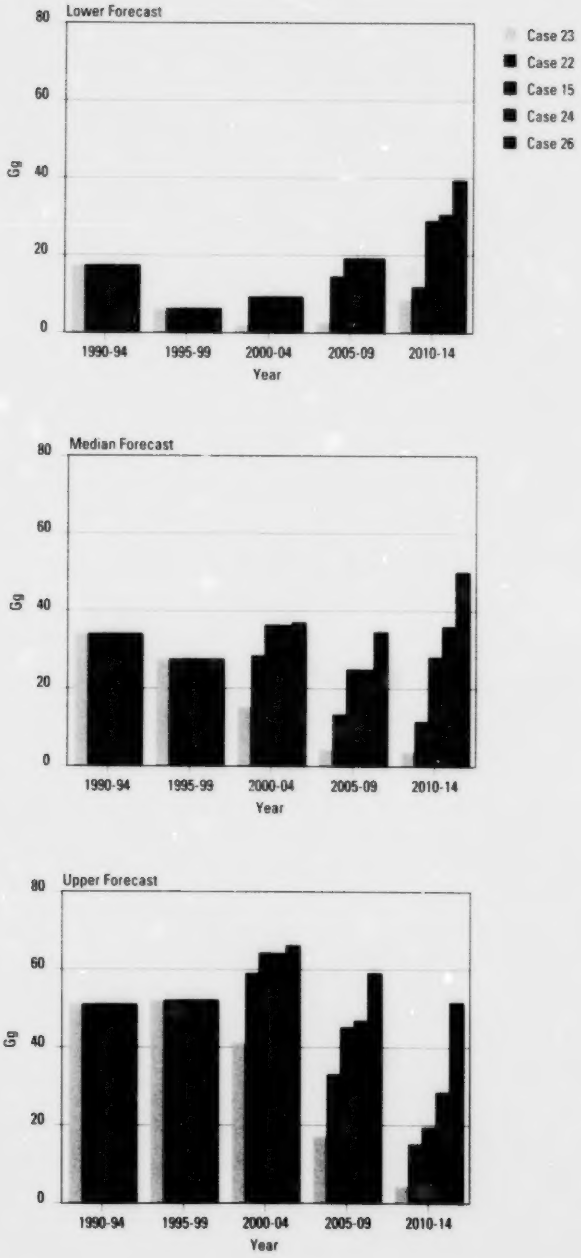
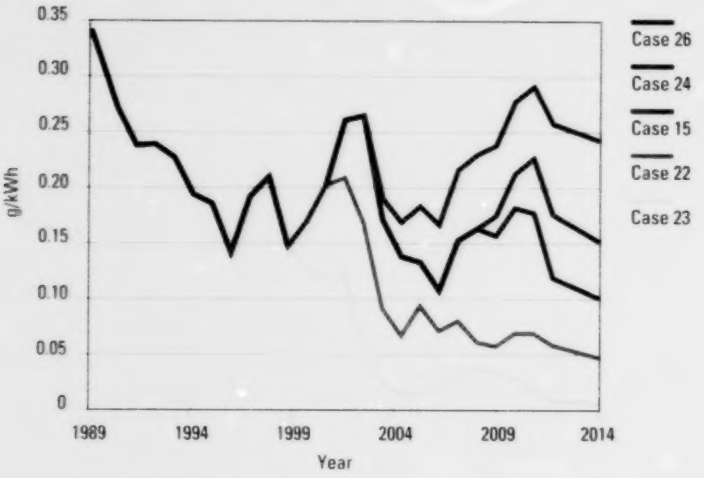


Figure 15–35 **Trends in NOx Emissions 1989–2014**



Trends in NO_x emissions, expressed in g/kWh of total Ontario Hydro generation, are shown in Figure 15–35. Cases 15, 22 and 23 show more declines in emission rates than Cases 24 and 26.

Environment – Carbon Dioxide Emissions

Carbon dioxide emissions from fossil generation are predicted to be a significant contributor to global warming. There are currently no regulations on CO_2 emissions. However, Canada's energy ministers have considered, as an illustrative target, a 20% reduction from 1988 CO_2 emissions by 2005.

In 1988, Hydro's CO_2 emissions were 31 Tg, making Hydro's illustrative target approximately 24 Tg per year. CO_2 emissions, which vary significantly among Cases, are shown in Figure 15–36.

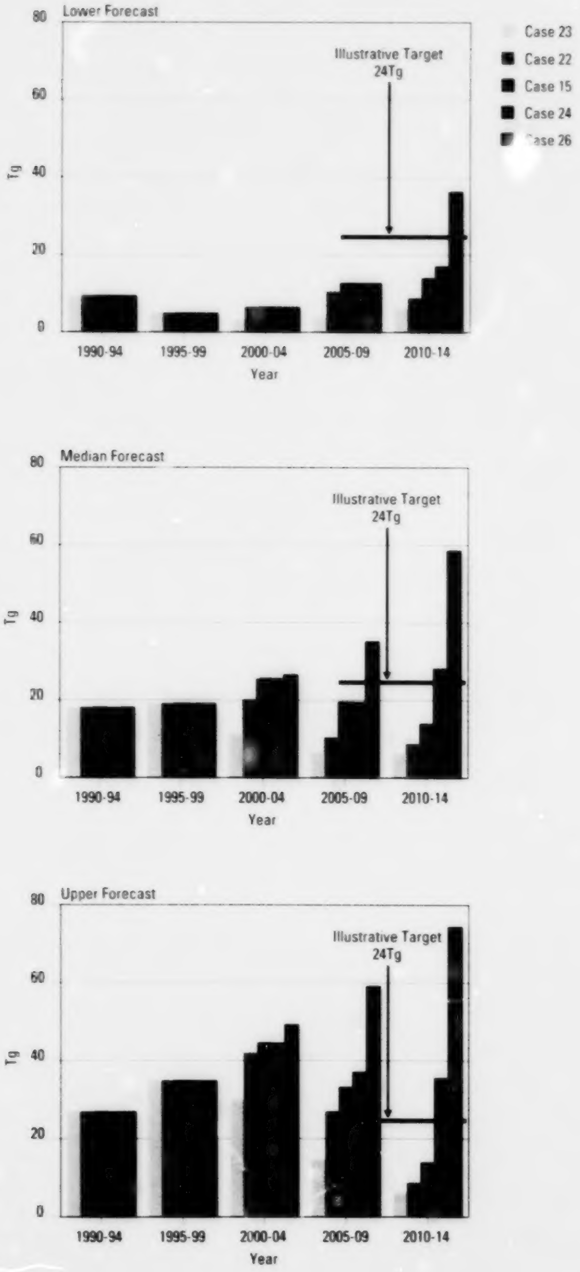
Under median forecast, Cases 24 and 26 exceed the target; Cases 15, 22 and 23 provide a margin below the target.

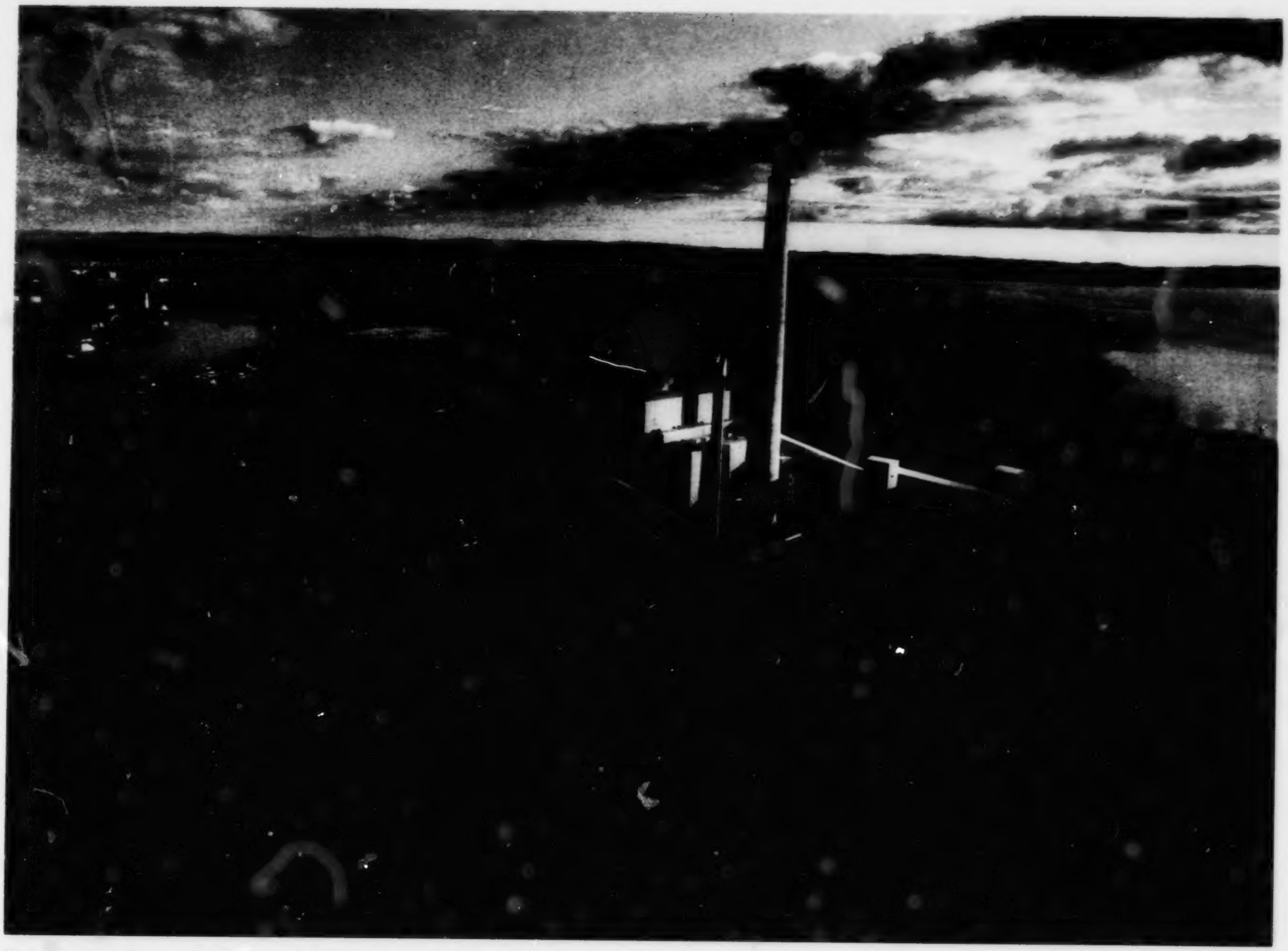
Under lower forecast, Case 26 exceeds the illustrative target.

Under upper forecast from 2005 to 2009, all Cases except Case 23 exceed the illustrative target. From 2010 to 2014, Cases 24 and 26 continue to exceed the target, Case 26 by two to three times.

Trends in CO_2 emissions, expressed in g/kWh of total Ontario Hydro generation, are shown in Figure 15–37. Case 26 produces higher emission rates by the end of the planning period; Case 24 is about the same; Cases 15, 22 and 23 are lower.

Figure 15–36 **Average Annual CO_2 Emissions**





At existing stations, sulphur dioxide limits are met by burning low-sulphur fuels and controlling emissions.

Mitigation of acid gas and CO_2 emissions is achieved by plan components, such as demand management, which do not involve the use of fossil fuels. To meet SO_2 and NO_x emission regulatory limits, Hydro employs a variety of control methods, including burning low-sulphur coal and installing scrubbers and combustion process modifications on selected existing coal-fueled units. All new CSC coal units considered in these Cases are fitted with SO_2 scrubbers and SCR for NO_x control.

Cost-effective, practical techniques for removing CO_2 from the flue gas of fossil-fueled generating stations are not commercially available.

Environment – Fossil Generation Waste

Wastes associated with coal generation include ash and scrubber (Flue Gas Desulphurization) waste (Figure 15–38). There are no significant wastes from oil or gas generation.

Ash and scrubber waste varies between Cases over the plan period. Compared to Case 15, Case 26 generates about 70% more, Case 24 about 20% more, Case 22 about 20% less and Case 23 about 40% less.

Total Case 15 ash and scrubber wastes, arising from 550 TWh of fossil energy production over the plan period, would occupy a cube about 285 m on each edge.

Some ash and scrubber wastes can be used in road beds, concrete products and other building products. The balance requires storage/disposal on the generating site and new off-site disposal sites.

Trends in fossil generation solid waste, expressed in g/kWh of total Ontario Hydro generation, are shown in Figure 15–39. Cases 26 and 24 produce more waste than Cases 15, 22 and 23.

Figure 15-37 **Trends in CO2 Emissions 1989–2014**

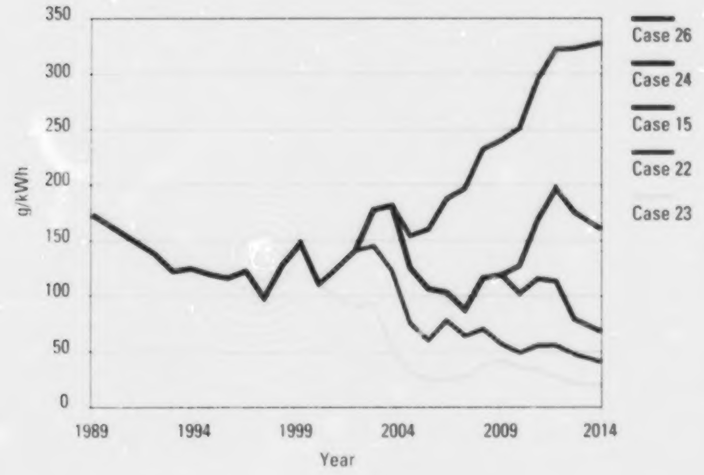


Figure 15-38 **Ash and FGD Waste 1989–2014**

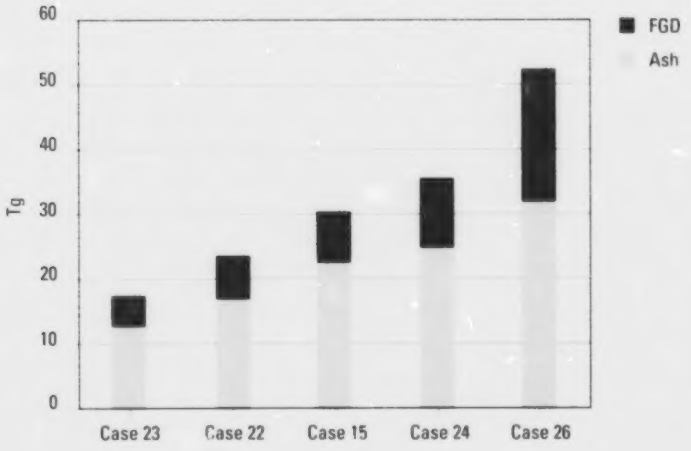
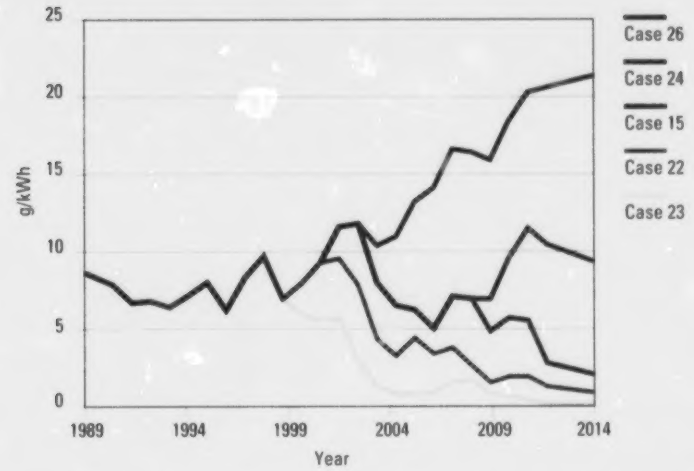


Figure 15–39 **Trends in Ash and FGD Waste Quantities 1989–2014**



Warm water discharged from Darlington is held in a diffuser-discharge tunnel before being released into Lake Ontario.

[illegible]

[illegible]

	Average Annual Production	Waste from Fossil Generation in Place by 2014		
	2010 - 2014	2014 - 2024	2014 - 2034	2014 - 2044
Case 26	3.7	37	74	111
Case 24	1.8	18	36	54
Case 15	0.8	8	16	24
Case 22	0.3	3	6	9
Case 23	<0.1	0.8	1.5	2.3

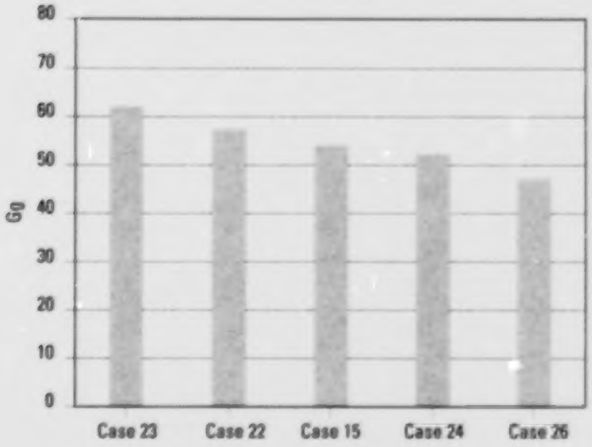
[illegible]

All five Cases produce significant quantities of waste by the end of the planning period. A number of options is available to significantly reduce waste. Ash from Hydro's coal-fired stations has historically been used for replacement/additive material in cement making; backfill material for mines and pit/quarry rehabilitation; and hazardous liquid stabilization. In 1987, about 19% of the ash produced by Hydro's coal-fueled stations was recycled. Hydro is actively pursuing a variety of opportunities to expand the reuse of ash.

Scrubbing SO_2 from the flue gas at coal-fueled stations produces a calcium sulphate (gypsum) waste that can, at additional cost, be used in the production of commercial grade wallboard. Hydro is actively negotiating with wallboard manufacturers to develop a market for synthetic FGD gypsum that will be produced at Lambton GS, starting in 1994.

IGCC has more easily managed solid waste and no scrubber waste.

Figure 15–41 **Nuclear Fuel Waste Quantities 1989–2014**



Installation of feeder tubing in Bruce Generating Station's reactor.

Ash and scrubber waste will accumulate at different rates after the plan period. Figure 15–40 shows rates and projections of waste quantities for 10, 20 and 30 year intervals from generation in place by 2014. Case 26, which uses CSC coal stations to meet new base load requirements, has significantly higher fossil waste volumes than the other Cases. Case 24, which uses one CSC coal station, has somewhat more wastes than the remaining Cases.

Environment – Nuclear Generation Radioactive Waste

Wastes associated with nuclear generation include used fuel and low-level radioactive wastes (Figures 15–41 and 15–42).

There is a variation in used nuclear fuel between Cases over the plan period. Case 26 generates the least, Case 23 the most. Relative to Case 15, Case 26 generates about 15% less; Case 23 generates about 15% more. Low-level radioactive waste (LLRW) quantities follow a similar pattern.

Putting these waste quantities into perspective, the used nuclear fuel of Case 15, arising from 2800 TWh of energy production over the plan period, would occupy a cube 28 m on edge. Volume is the typical measure for LLRW, instead of mass, due to the heterogenous nature of the waste. The approximate weight of the low-level radioactive waste associated with Case 15 is 20 Gg.

Trends in radioactive waste, expressed in g/kWh of total Ontario Hydro generation, are shown in Figure 15–43. All Cases show an increasing trend except Case 26.

Construction of nuclear stations requires the largest workforce among supply options.

Figure 15–42 **Low Level Radioactive Waste Quantities 1989–2014**

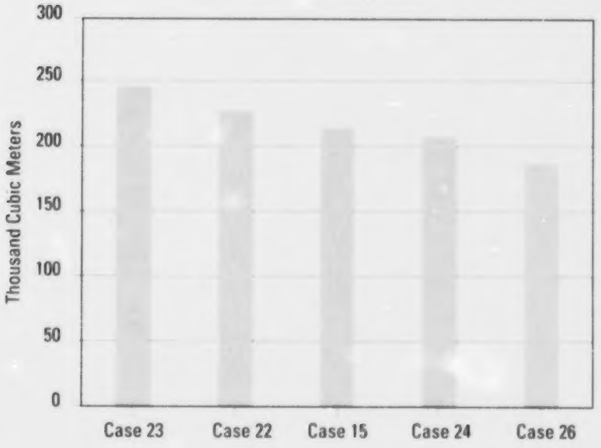
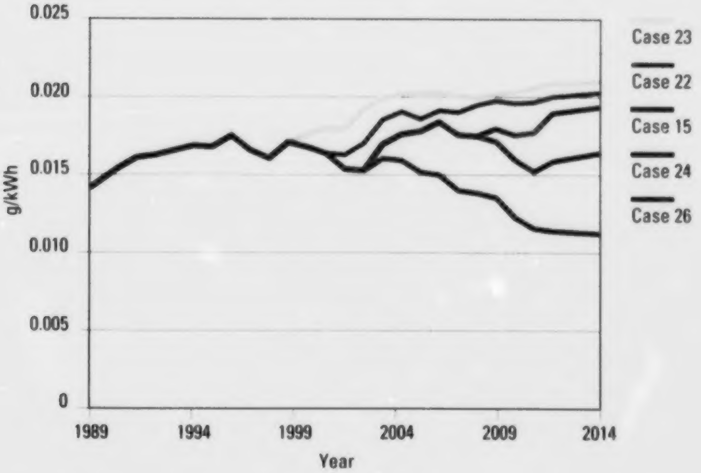


Figure 15–43 **Trends in Used Nuclear and LLRW Quantities 1989–2014**



Used nuclear fuel will accumulate at different rates after the plan period. Figure 15–44 shows the rates and projections for 10, 20 and 30 year intervals from nuclear generation in place by 2014. Case 23 has the highest accumulation of used nuclear fuel, followed by, in declining order, Cases 22, 15 and 24. Case 26 has the least, by a sizable margin, as no additional nuclear facilities are added.

Environment – Land Use

All Cases have comparable new land use requirements because the differences between Cases are small for new generating station sites, new transmission circuits and new waste management facilities.

Generating stations typically use 300 to 500 hectares. In addition to the use of the existing Wesleyville and Darlington B sites, Cases 15, 22, 24 and 26 require land for two new sites; three new sites are required for Case 23. The use of existing sites in all Cases reduces the requirement for new sites.

Under median forecast, transmission line right-of-way requirements are about 13,000 hectares in all Cases.

Land required for fossil generation wastes is determined by the amount of coal burned, the environmental control concepts adopted and the extent to which by-products are utilized. Land use for fossil waste ranges from about 300 to 600 hectares.

The nuclear fuel waste disposal facility needed for existing nuclear facilities will also accommodate used fuel quantities for new nuclear facilities in all Cases under all load forecasts. Hence, there is no incremental nuclear fuel waste management land requirement.

Figure 15-44 Nuclear Generation Used Fuel

[illegible]

	Average Annual Production 2010 – 2014	Waste from Nuclear Generation in Place by 2014 2014 – 2024	2014 – 2034	2014 – 2044
Case 26	1.6	16	32	48
Case 24	2.2	22	44	66
Case 15	2.5	25	50	75
Case 22	2.7	27	54	81
Case 23	2.8	28	56	84

[illegible]

A nuclear fuel waste disposal concept is being developed under the Ontario/Canada Nuclear Fuel Waste Management Program, with Atomic Energy of Canada Limited taking the lead. Ontario Hydro is leading the demonstration of transportation of these wastes. Preparation for public review of transportation and disposal, through the Federal Environmental Assessment Review Panel, has started.

Once the disposal concept is approved, siting studies can begin. In the interim, Hydro will continue to store used fuel at the nuclear stations. A final repository is planned to be in place after 2020.

Included in Ontario electricity rates is a provision for the cost of nuclear fuel waste disposal and decommissioning of nuclear stations.

Social Acceptance And Other Social Considerations

The DSPS presents guidelines for the development and evaluation of demand/supply plans. These guidelines incorporate the results of public consultation during which Hydro gained a better understanding of public values, concerns and expectations.

Whether demand/supply plans, based on the DSPS, are seen as socially acceptable will depend on:

- How well Hydro has taken into account changing social values related to, for example, environmental performance and maximum achievement of preferred options – demand management, NUGs, hydraulic generation and station rehabilitation;
- The choice of supply options, which is both a societal and local concern.

Social acceptance of plans will be evaluated through the environmental assessment process, which will provide opportunities for public input.

Social acceptance and other social considerations will also be an important factor in siting supply options.

Economic Impact – Gross Domestic Product (GDP) and Employment

All demand/supply plans will generate significant employment across the province. Differences in total employment depend in large measure on the fossil and nuclear components in each Case. Over the lifetime of a CANDU nuclear station, typical Canadian and Ontario content is over 90%, about twice that of a conventional steam cycle coal station.

A provincial GDP and employment impact assessment was prepared, comparing Cases 22 and 24 to Case 15. The assessment period is to 2009.

[illegible] Maximum Use of Land

Transmission requirements dominate total land use associated with all five planning Cases. Opportunities to reuse existing rights of way for new transmission and to provide maximum opportunities for secondary use on Hydro rights-of-way will reduce future land requirements and optimize use of existing and future land holdings. Typically the amount of land not available for secondary use within a given right-of-way is less than one percent of the total.

Making maximum use of existing generating station sites before developing new sites and providing opportunities for compatible secondary uses is also preferred.

The GDP impacts are expressed in constant 1989 dollars and the employment impacts are expressed in person-years and take into account labour productivity gains in each year.

All Cases will produce additional GDP impact and create more employment. For example, on average, Case 15 will produce approximately a $4 billion GDP impact annually (1.1% of annual provincial GDP) and generate about, on average, 58,000 person-years of employment annually (1% of the annual provincial labour force).

Relative to Case 15, Case 22 produces $95 million more GDP impact and generates 1,100 more person-years of employment annually over the 1989-2009 period. On average, the differences between the Cases represent 0.03% of the annual provincial GDP and 0.02% of the annual provincial labour force.

Relative to Case 15, Case 24 produces $115 million less GDP impact and generates 1,200 less person-years of employment annually from 1989 to 2009. On average, the differences between the Cases represent 0.03% of the annual provincial GDP and 0.02% of the annual provincial labour force.

Further assessment shows that similar annual differences continue when the analysis period is extended to 2040.

Results for Cases 26 and 23 can be inferred. Case 26, with more base load CSC coal generation and no CANDU nuclear, would have lower GDP and employment impact than Case 24. Case 23, with more CANDU nuclear generation, would have higher GDP and employment impact than Case 22. These impacts would still be small percentages of the annual provincial GDP and annual labour force.

This impact analysis only measures the gross impacts of Ontario Hydro activity and does not reflect the net impact to the Ontario economy. If the Ontario economy is at full employment over this period, some of the jobs created by the construction of new facilities in Ontario would be drawn from other construction projects or through migration. Therefore, the net impact could be some fraction of the figures presented here.

Economic Impact – Balance Of Trade

Expenditures within and outside Canada vary between Cases, mostly due to quantities of imported fuel (e.g. U.S. coal) and equipment.

Electricity exports, which also vary between Cases, significantly favour the Canadian balance of trade.

Over a 40-year-period, assuming a 2002 in-service date and 80% average annual capacity factor:

1. $750 million dollars (1989 present value) is spent within Canada to purchase fuel for a CANDU station.
2. $3,500 million dollars (1989 present value) is spent outside of Canada to purchase fuel for an equivalent CSC coal station.

Estimates of differences in balance of trade between the Cases have been made beyond the study period, to 2040, to capture a greater portion of major supply option lifetimes.

Among the five Cases, Cases 23 has the most favourable impact and Case 26 has the least favourable impact on balance of trade. Compared to Case 15, Case 22 has a higher impact of $115 million annually (constant 1989 dollars) and Case 24 has an unfavourable impact of $57 million annually (constant 1989 dollars).

These differences total to about $1 billion ($1989) more favourable trade balance for Case 22 and about $300 million ($1989) less favourable trade balance for Case 24.

Customer Satisfaction

There are many customer satisfaction considerations in the development and delivery of the Demand Management Plan. Customer satisfaction, as it relates to major supply, is determined by the extent to which the other criteria are satisfied, eg, cost, reliability, environmental protection.

Reliability Standard – Generation Reserve Margin

As discussed in Chapter 4, Ontario Hydro's reliability standard of 25 system minutes of customer unsupplied energy can be translated to a generation reserve margin of 24%. All Cases aim to maintain this reserve margin.

Reserve margins for the five Cases are shown in Figure 15–45. All Cases maintain adequate reserve margin under median growth, have a temporary shortfall under upper forecast,

Provincially

Certain segments of the provincial population may conclude they are more affected by the Demand/Supply Plan than others, because of cultural background, socio-economic position, lifestyle or livelihood. As a result, they may take a more active interest and involvement in its review.

For example, resource-based industries, manufacturing and other sectors of the provincial economy will have an interest in either the supply of resources, goods and services for the construction and operation of the electricity system, or the availability of sufficient, low-cost electricity to expand their own businesses. In addition, skilled tradesmen across the province may have an interest in the potential for construction employment associated with plans and/or the dislocation caused by changing jobs or work location. Lower income and fixed income segments may be concerned with electricity rates rising in the long term.

Other segments of the provincial population may be concerned with equity issues related to the depletion of non-renewable resources, the long-term effects of fossil generation on the climate and the atmosphere, or the inter-generational sharing of risks and benefits of nuclear generation and waste management.

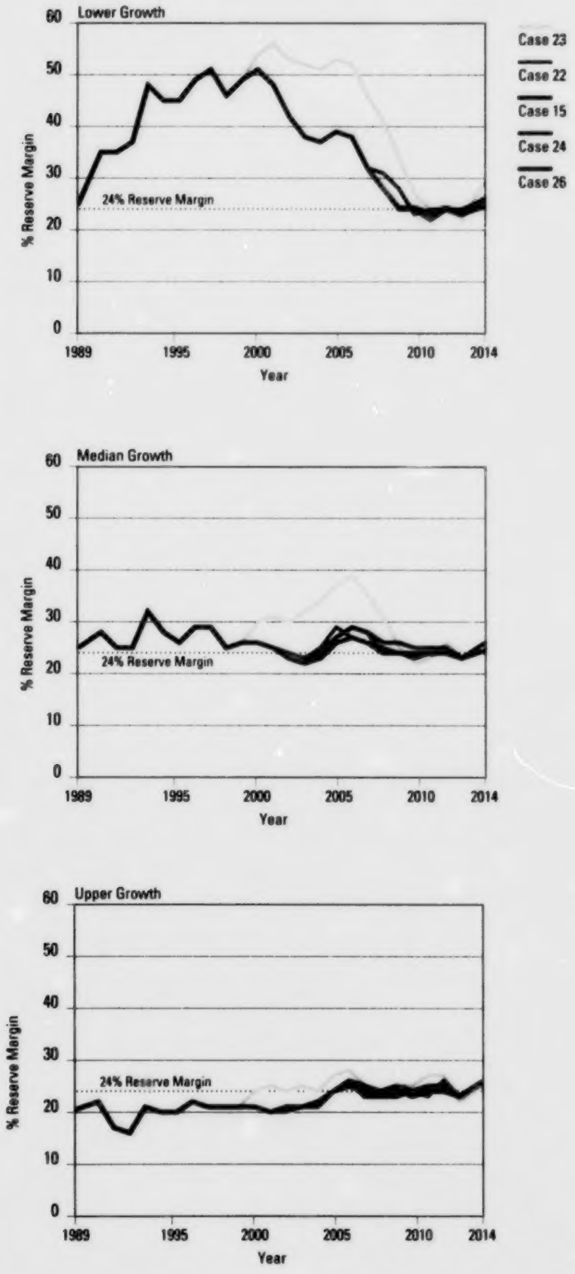
Regionally

People living in certain regions of Ontario may have a particular interest in parts of the Demand/Supply Plan. For example, northern residents may have a particular interest in the orderly development of hydraulic stations or the location of a major supply facility. Other segments of regional populations may have a significant interest in how plans could affect recreation, land use, business and traditional lifestyles.

Locally

Communities located near a proposed generating facility generally have a strong interest in the potential impacts – both positive and negative – of the development. The extent and significance of impacts depends on the fit between project and community characteristics. This fit typically includes project and community size, labour requirements and availability, and project schedule. The local availability of skilled labour is a major factor, as the influx of workers and their families may strain community facilities, services, administration and financial resources. However, many community impacts can be avoided or mitigated with Ontario Hydro's impact management programs.

Figure 15–45 **Reserve Margins**



and are in surplus for most of the plan period under lower forecast.

Up to 2000, the reserve margins are the same in all Cases for each of the load forecasts, because little major supply is added before then.

Median Forecast

Under median forecast, the reserve before 2000 is above the standard for two reasons. Darlington comes into service and demand management, non-utility generation and hydraulic developments make an increasing contribution. All Cases maintain a reserve margin close to 24% from 2004 to 2014. Case 23 exceeds the reserve margin, in some years by a large amount, from 1999 to 2009.

Upper Forecast

Under upper forecast, reserves in the 1990s drop to about 16 to 20%. This is because there is not sufficient time to build supply facilities required to maintain reserve margins in the early to mid 1990s. Beyond the mid 1990s, restoring reserve margins depends on how quickly the trend to higher load growth is recognized and on having sufficient approvals in hand to react to higher load growth in a timely fashion. All Cases except Case 23 restore reserves to 24% by about 2005; Case 23 restores reserves several years sooner.

Lower Forecast

Under lower forecast, reserve margins rise throughout the 1990s as Darlington comes into service and the Demand Management, Non-Utility Generation, Hydraulic Plans and the Manitoba Purchase are implemented. Gradually, with load growth and with the retirement of some existing generation, reserve

[illegible]

Cost Component	Case 23	Case 22	Case 15	Case 24	Case 26
Nuclear					
Capital	5,165	3,382	2,189	1,639	0
OM&A	2,553	1,675	1,083	810	0
Fossil					
Capital	92	208	517	908	1,926
OM&A	0	25	73	262	847
Fuel related costs associated with growth beyond 1993	(961)	(77)	936	1,387	2,897
Bulk Transmission Cost Difference from Case 15	287	101	BASE	0	(40)
Total	7,137	5,314	4,798	5,006	5,630
Difference from Case 15	2,339	516	BASE	208	832

More than 3/4 of total costs to 2014 are associated with operating and maintaining the existing system.

margins return by 2008 to 24% in all Cases except Case 23, which maintains high reserves to 2011.

Major Supply Costs – 25-Year Period

Costs were evaluated using concepts described in Chapter 6.

Figure 15–46 shows costs for Ontario Hydro new major supply in the five Cases. The costs are the present value of the levelized costs allocated to the study period, using the median forecast of load and cost estimates such as fuel cost, capital costs and discount rate.

Nuclear and fossil station costs are the life cycle costs allocated to the period up to 2014.

Most future fuel costs will be incurred to meet existing demand. To better understand the impact of the Cases, the fuel costs shown in Figure 15–46 are those for meeting growth in demand beyond 1993. They include the cost of fuel from new supply options and their effects on deployment of the existing system. For example, in Case 24 there is higher cost, of $1,387 million, associated with fuel to meet growth. On the other hand, in Case 22, the fueling cost from 1989 to 2014 is reduced by $77 million, because most of the additional energy is produced by low-cost nuclear fuel that displaces some more expensive fuel in use in 1993, the reference year.

Differences in bulk transmission costs are shown relative to Case 15.

Differences in Ontario Hydro major supply costs are shown in the bottom line of Figure 15–46. Relative to Case 15, Cases 23 and 26 have larger cost differences than Cases 22 and 24.

Case 23 is higher in cost because CANDU stations operate at low capacity factors, where they are not cost competitive, (Figure 15–3).

Case 26 is higher in cost because fossil stations operate at high capacity factors, where they are not cost competitive, (Figure 15–3).

[illegible]

	Case 23	Case 22	Case 15	Case 24	Case 26
Cost of New D/S Options					
Allocated to 1994 – 2014					
Nuclear – Capital	5,165	3,382	2,189	1,639	0
– OM&A	2,553	1,675	1,083	810	0
Fossil – Capital	92	208	517	908	1,926
– OM&A	0	25	73	262	847
Acid Gas Controls	441	441	441	441	441
Manitoba Purchase	1,331	1,331	1,331	1,331	1,331
Hydraulic – Capital	1,189	1,189	1,189	1,189	1,189
– OM&A	200	200	200	200	200
Load Reducing Options DM&LD-NUGS	3,094	3,094	3,094	3,094	3,094
Purchase NUGs	1,619	1,619	1,619	1,619	1,619
Transmission	1,665	1,479	1,378	1,378	1,338
Distribution	2,998	2,998	2,998	2,998	2,998
Total Cost of New D/S	20,347	17,641	16,111	15,868	14,982
Fuel-Related Costs					
Cost Associated with Existing Demand	14,046	14,046	14,046	14,046	14,046
Cost Associated with Growth Beyond 1993	(961)	(77)	936	1,387	2,897
Total Fuel	13,085	13,969	14,982	15,433	16,943
Cost of Existing System Allocated to 1989 – 2014	42,898	42,898	42,898	42,898	42,898
Total Cost of New D/S Options and Operating the Existing System	76,330	74,507	73,991	74,199	74,823
Cost Differences from Case 15	2,339	516	BASE	208	832

There is uncertainty in the estimates of all cost components in each case. A probability analysis indicates a high confidence (90%) that Case 15 is the lowest cost Case.

Total Demand/Supply Option Costs – 25-Year Period

Total customer costs for other D/S options and the cost of operating the existing system during the plan period are shown in Figure 15–47 to provide a context for Ontario Hydro major supply costs. The following costs are shown:

Nuclear and fossil capital and OM&A are those costs previously shown in Figure 15–46. *Acid gas control* costs include scrubbers to reduce SO_2 and combustion process modifications to reduce NO_x.

Manitoba Purchase costs start in 1998.

Hydraulic costs are for 2850 MW of developments by 2014.

Load reducing options, ie, demand management and load displacement NUGs, include both utility and customer costs. These are a substantial component of future D/S plan costs.

Purchase NUGs include payments from Hydro to NUGs for electricity purchases.

Transmission and Distribution costs include expenditures by municipal utilities, because these costs are part of total customer costs. Costs vary between Cases, because bulk transmission requirements and timing are different.

Fuel related costs are divided into two components. The first represents costs associated with meeting existing demand. This includes the cost of fuel from 1989 to 1993, plus an assumption that the manner in which the existing system meets 1993 demand continues from 1994 to 2014. The second component is the cost of meeting forecast load beyond 1993, which was shown earlier in Figure 15–46. Fuel related costs include a small allowance for profits from electricity export sales from nuclear generation.

The cost of the existing system includes demand management and non-utility generation from 1989 to 1993, and future operation, maintenance and rehabilitation of the existing system.

Costs in Figure 15–47 do not include the financing or depreciation costs for the existing system, because they are derived from sunk costs and are not affected by demand/supply additions. This figure shows that a large part of future costs relates to operating the existing system and is common to all Cases.

More than 3/4 of total costs to 2014 are associated with operating and maintaining the existing system.

Cost differences shown in Figure 15–47 are the same as those previously shown in Figure 15–46, because differences in cost are associated with major supply options. All other components are common to all Cases.

Figure 15–48 displays the total cost for Case 15.

Cost Differences – 25-Year Period

Figure 15–49 tabulates the differences in major supply cost, using Case 15 as a base. The total cost of Ontario Hydro's major supply are also shown on the left column. Figure 15–46 showed the Ontario Hydro major supply cost under median forecast.

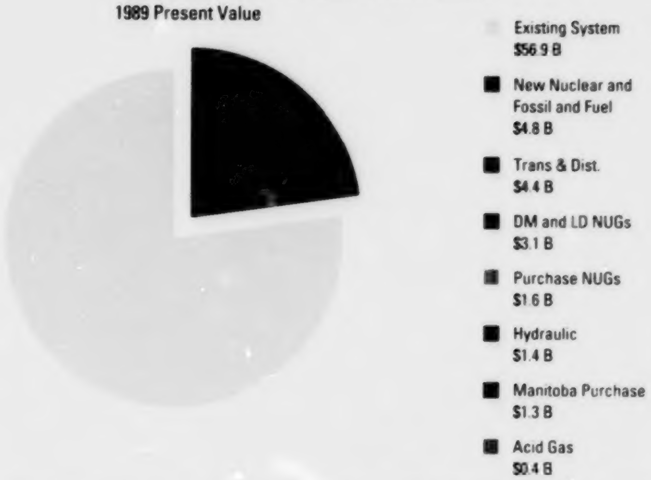
Figure 15–49 also shows the differences for upper and lower forecasts.

All Cases cost more than Case 15 under all load forecasts.

Cost Confidence

Until now, costs for three load forecast paths have been shown – median, upper and lower forecasts. This section presents results for the other two load paths, the branch upper and branch lower paths, which are described earlier in this chapter.

Figure 15–48 **Total Costs for Case 15 – 1989 to 2014**
Median Load Growth and Median Cost Estimates
1989 Present Value



Total Cost $73.9 B

Load Forecast	Ontario Hydro Major Supply Cost of Case 15	Cost Differences				
		Case 23	Case 22	Case 15	Case 24	Case 26
Upper	12,191	1,164	167	BASE	221	1,214
Median	4,798	2,339	516	BASE	208	832
Lower	2,149	2,154	314	BASE	17	187

This section also introduces cost estimates of fuel costs, capital costs and discount rates that represent a band of uncertainty. For each estimate, a range with an 80% confidence is established. Ranges are represented by three levels: median, upper, and lower, each with a corresponding probability.

Results of the analysis provide a band of costs, based on possible variations in load forecast and cost estimates. Using this approach, the cost of a Case is not a single number, but a distribution or band representing 405 possible outcomes.

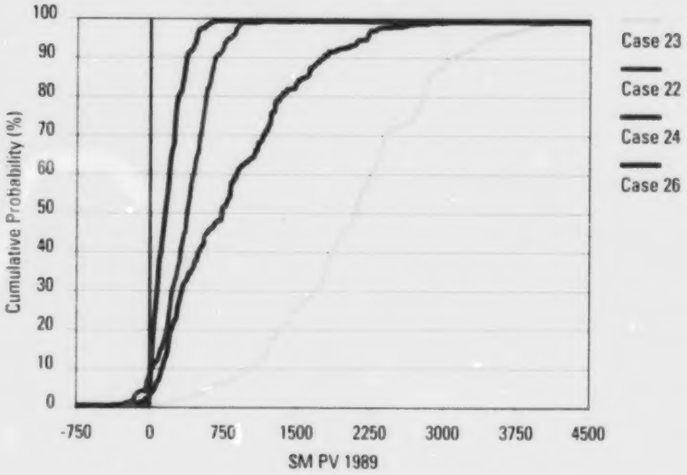
One way to compare Cases is to plot the differences between the lowest cost case, Case 15, and all others. Figure 15–50 shows the cumulative probability distribution of cost differences between Case 15 and the other Cases.

When a cost difference line is left of 0, it indicates the probability of that Case costing *less* than the base Case; if it is to the right, it indicates the probability of the Case costing *more* than the base Case. If the distribution of costs for one Case is always to the left of another, then the one to the left is lower in cost under all conditions.

The figure shows, for example, that there is less than a 10% probability that Case 22 could be lower in cost than Case 15, and greater than 90% chance that it will be higher in cost. The low end of the figure shows that there is negligible chance that Cases 23, 24 or 26 would be lower in cost than Case 15. The top end of the figure shows that all Cases could be significantly higher than Case 15. Cases 26 and 23 could be higher by a substantial margin.

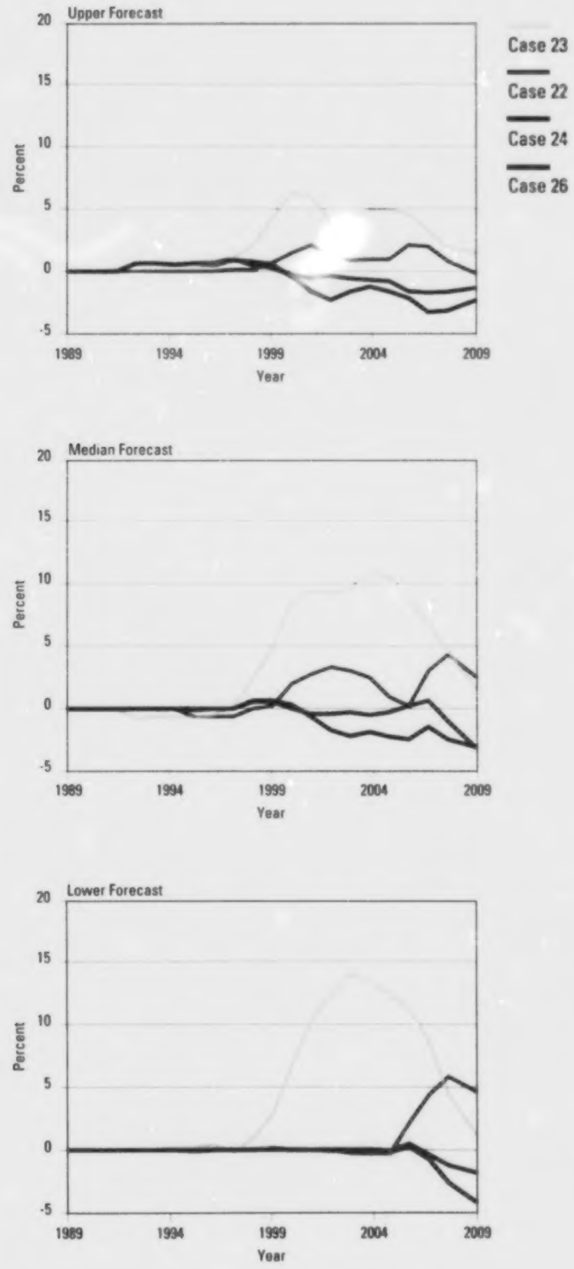
There is uncertainty in the estimates of all cost components in each Case. A probability

Figure 15–50 **Cost Differences Relative to Case 15**



Description of Cost Difference	**Case 23**	**Case 22**	**Case 15**	**Case 24**	**Case 26**
Differences Based on Median Estimates (shown in Fig. 15–46)	2,339	516	Base	208	832
80% Confidence Band	1,020 – 3,195	30 – 690	Base	30 – 390	120 – 1,770
Expected Cost Difference	2,097	365	Base	187	857

Figure 15–52 **Impact on Electricity Prices Relative to Case 15**



analysis indicates a high confidence (90%) that Case 15 is the lowest cost Case.

Figure 15–51 summarizes cost differences relative to Case 15. For reference, cost differences shown earlier for median estimates in Figure 15–46 are repeated. Also presented is the 80% confidence band on cost difference drawn from the cumulative probability distribution figure; and expected cost differences. Expected cost, introduced in Chapter 6, is a weighted cost determined by the sum of the 405 cost outcomes multiplied by their respective probabilities.

Illustrative Costs – Siting And Transmission

The costs shown to this point assume the first major base load generating station is east of Toronto. To illustrate how cost may vary with siting, another siting sequence was evaluated. It assumes the first major station is in Northern Ontario. Costs increase by about $150 to $250 million, because transmission costs occur earlier and the higher cost site (North Channel area) is developed earlier.

Electricity Prices

Impacts on electricity prices, to the year 2009, are presented in this section. Financial impacts beyond 2009 are influenced by costs associated with as yet undefined new facilities with in-service dates beyond 2014.

Under Case 15, real electricity prices over the next 20 years are expected to remain within ±10% of current levels. The impacts on electricity prices relative to Case 15 are shown in Figure 15–52 for median, upper and lower forecasts. For the first decade of the study period, there are essentially no differences in prices, while from 2000 to 2009, electricity prices for Cases 22, 24 and 26 are generally within ±3% of Case 15. The outlook is significantly less favourable under Case 23, with prices projected to be as much as 10 to 15% higher than Case 15.

Cases 24 and 26 have slightly more favourable electricity price outlooks than Case 15 during the study period, due to the initial accounting cost advantage enjoyed by fossil stations over nuclear stations. The combined accounting cost, discussed in Chapter 6, of capital, OM&A and fuel in the first few years of a station's life are higher for nuclear generation than for coal generation.

Prices for Cases 24 and 26 become higher than Case 15 beyond 2009, as the accounting cost associated with capital declines.

Borrowing Requirements

Figure 15-53 shows projected annual real net borrowing levels. Borrowing levels are generally

The total cost of a major supply case depends on the combination of load path and cost estimates assumed. This cost analysis considers five load paths (upper, branch upper, median, branch lower, lower) and three values for each cost estimate (upper, median, lower). When each load path is combined with each value of the cost estimates, there are 405 cost outcomes for each major supply case.

Load Growth – 5 Paths
Capital Costs – 3 Estimates
Uranium Fuel Costs – 3 Estimates
Fossil Fuel Costs – 3 Estimates
Discount Rate – 3 Estimates

Figure 15-53 **Annual Net Borrowing**

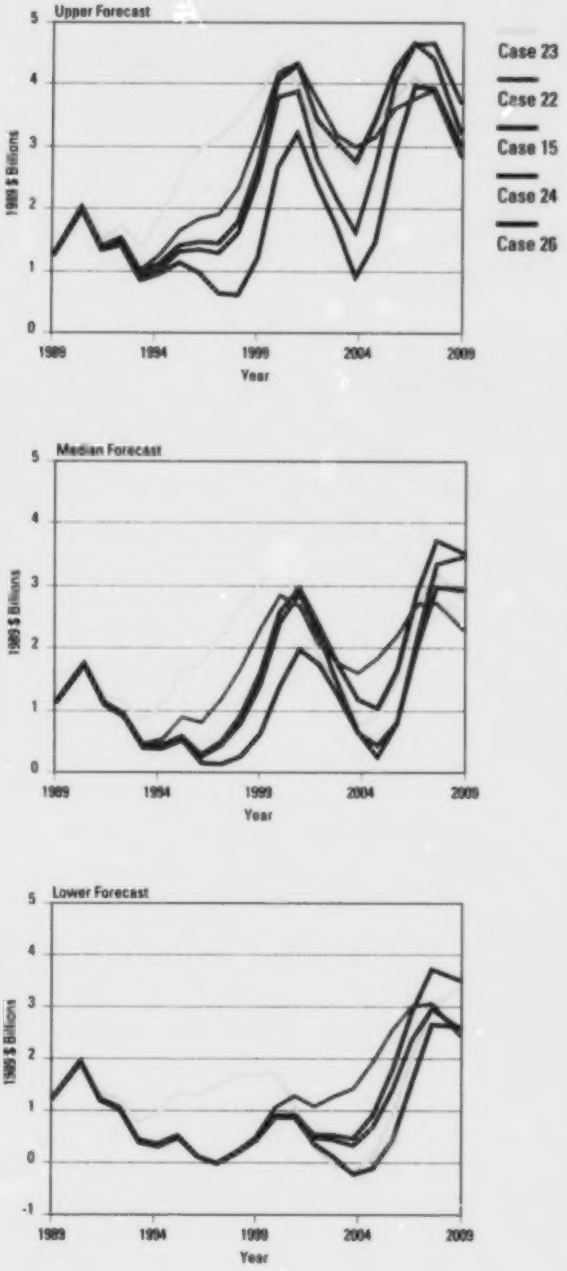
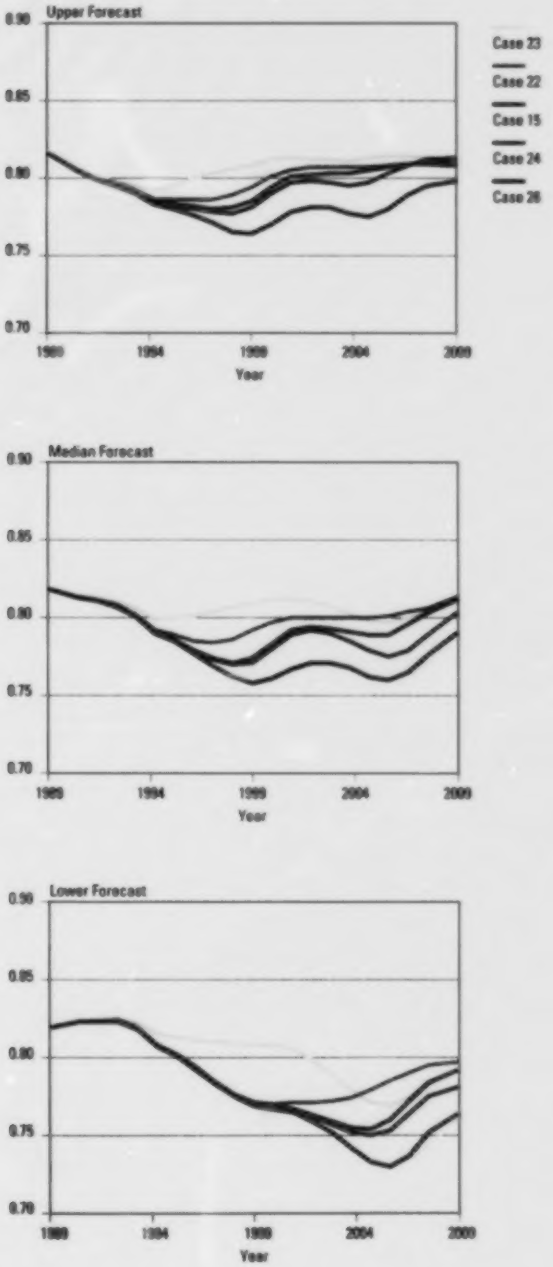


Figure 15–54 **Debt Ratio**



expected to peak around 2000 and again around 2008, corresponding to the need for major new generating facilities. Borrowings are highest for those Cases having the most nuclear generation, and lowest for those Cases using the most fossil generation, as the capital cost of nuclear generation is higher than that for fossil. Annual real net borrowing levels are ±$1.5 billion of those for the Case 15.

Relative to Case 15, cumulative real net borrowings over the period to 2009 are projected to be up to $7 billion higher under Case 23, up to $3 billion higher under Case 22, up to $4 billion lower under Case 24 and up to $13 billion lower under Case 26.

While the various Cases provide a wide range of borrowing requirements, gross annual borrowings have peak requirements that range up to twice current levels (in 1989$). In years when borrowing requirements are high, Ontario Hydro may have to obtain funds at interest rates closer to the upper range considered in the cost confidence analysis, and may have to accept foreign exchange risk.

Financial Performance – Debt Ratio

The outlooks for the Corporation's financial performance, as measured by the debt ratio (debt divided by total capital), are illustrated in Figure 15–54. They are based on Ontario Hydro's current net income policy, which is under review. For all Cases, the debt ratio is generally expected to remain in the 0.75 to 0.81 range throughout the next 20 years, rising slightly whenever major new generating stations near completion. This outlook may be compared to Hydro's debt ratio over the past twenty years, which has ranged from 0.73 to 0.85. A comparison of debt ratios between Cases generally reflects similar trends (ie, those Cases having higher borrowing levels also have higher debt ratios).

Cost Differences Beyond The Study Period

Major differences in costs occur after 2014. This is because, on average, only about six years of the 40-year-life of base load options occur within the plan period. The true differences between Cases over the full life of the base load options are very large. Estimates of cost differences beyond the study period are shown in Figure 15–55.

Cost differences between Case 15 and the other Cases grow with extension of the study period.

The cost difference between Case 26 and Case 15 over the plan period is $832 million; if the study period is extended to 2044, the cost difference increases to $3,044 million.

Another way to demonstrate the large cost implications in the post 2014 period is to compare the life time costs of the base load options.

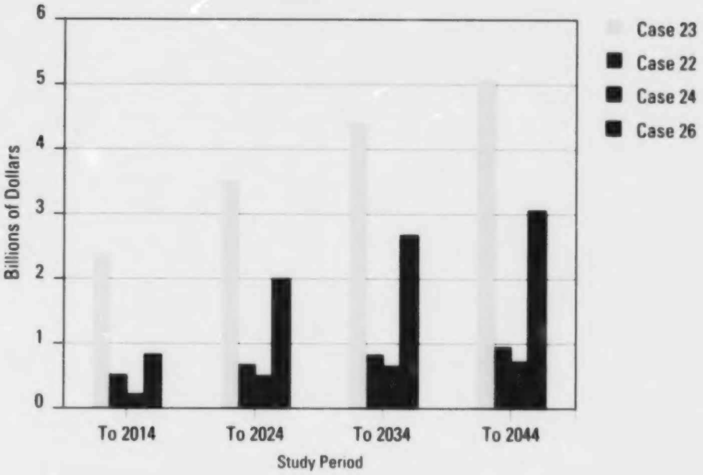
The levelized unit energy cost of the CANDU base load option is 3.1 to 3.4 cents/kWh ($1989). The levelized unit energy cost of the lowest cost fossil option CSC – US Coal is 3.9 to 4.2 cents/kWh ($1989). The present value of a coal station is about 25% higher than an equivalent 4 x 881 MW CANDU nuclear station. Over its 40-year-life, one CANDU station put in service in 2010 represents savings of $1.25 billion ($1989).

Technical Soundness

Most of the options employed in the five Cases use conversion processes and environmental controls with a proven track record in Ontario or other parts of the world.

Figure 15–55 **Cost Differences Beyond 2014 Relative To Case 15**

1989 Present Value



However, as discussed below, there are technical soundness considerations associated with certain components in the five Cases.

IGCC Option

The first phase of the IGCC option, gas or oil-fired CTUs, is used in all Cases to meet peak requirements and to permit additional phases to be added later, if required. The limited experience with 150 MW CTUs is discussed in the next section.

The CTU first phase and the combined cycle second phase are proven processes worldwide. The third phase, coal gasification, is an established process, but has not been extensively used commercially in the size called for in the Cases.

Most Cases would be affected by limitations that reduce the effectiveness of conversion to the full IGCC option. Case 23 would be less affected, because of its limited reliance on IGCC. In Cases 24 and 26, the IGCC option could replace base load coal options when it becomes more proven.

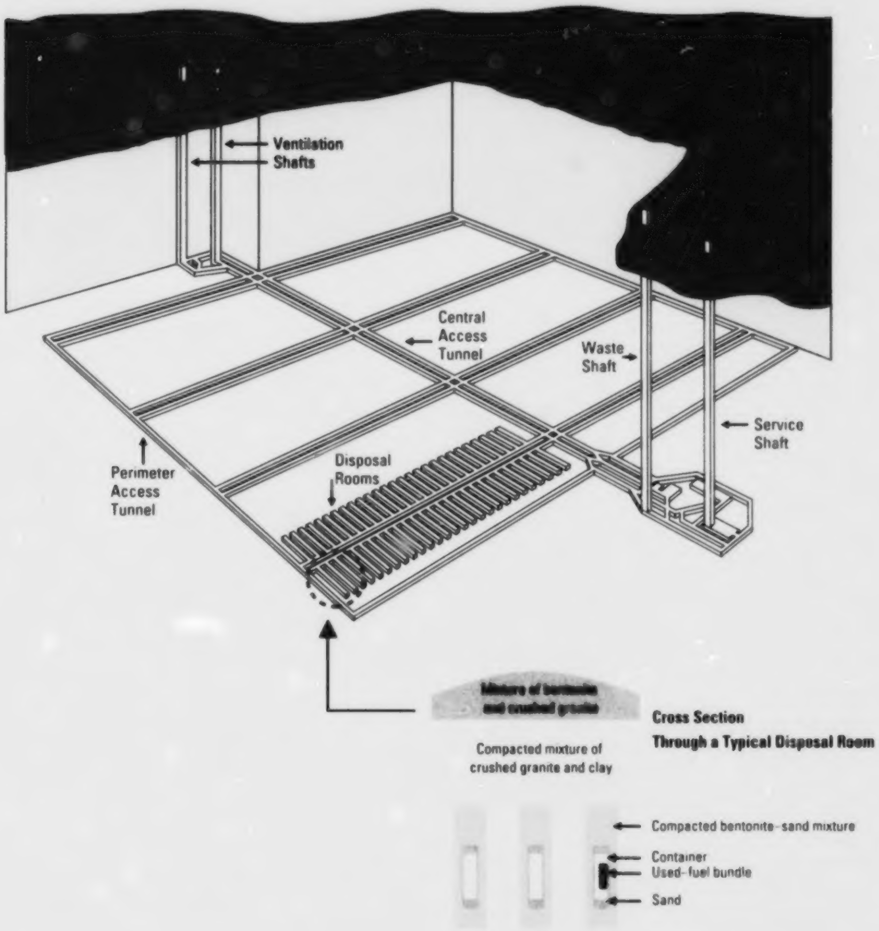
CTU Option

All Cases employ 150 MW CTUs, which were only recently introduced for commercial service. If their performance or availability does not meet requirements, the Cases could be modified to use 60 to 90 MW CTUs, which have been in commercial operation for several years. More units would be required and costs would increase slightly, because some of the economies of scale would be lost. Again, Case 23 may be less affected, as it employs fewer CTUs.

NO$_x$ Control

Selective catalytic reduction (SCR) is the NO$_x$ control proposed for new base load coal stations in Cases 24 and 26. SCRs have been used in

Figure 15–56 **Concept for Disposal of Nuclear Fuel Wastes**



Ventilation Shafts
Central Access Tunnel
Waste Shaft
Service Shaft
Perimeter Access Tunnel
Disposal Rooms
Mixture of bentonite and crushed granite
Cross Section Through a Typical Disposal Room
Compacted mixture of crushed granite and clay
Compacted bentonite–sand mixture
Container
Used–fuel bundle
Sand

Source: Managing Canada's Nuclear Fuel Wastes. Atomic Energy of Canada Ltd., WWM-39-05-01, page 18

Europe. SCRs have not been used commercially in North America. North American coals, have different characteristics than European coals. As a result, it is uncertain how effective they will be and how frequently the catalyst will need replacement – a major cost factor.

The costs of Cases 24 and 26 would increase if SCRs do not meet expectations.

All Cases use CTUs. The NO_x Control method assumed in Hydro's cost estimates is steam or water injection. Combustion modifications and SCRs, now under development, may be more effective.

The cost difference between Case 26 and Case 15 over the plan period is $832 million; if the study period is extended to 2044, the cost difference increases to $3,044 million.

Scrubbers for SO_2 Control

All Cases employ scrubbers at some existing coal stations to control acid gas emissions; Cases 24 and 26 employ scrubbers at all new base load coal stations.

Scrubbers have been proven worldwide. Ontario Hydro will install its first scrubbers at Lambton in 1994.

Scrubbers will play an important role in all Cases.

CSC Coal Unit Size

Cases 24 and 26 employ 800 MW coal units. This unit size is used in the US, but is new to Ontario Hydro. If closer examination during preliminary engineering shows that it is not suited to Hydro's system, it would be possible to substitute, at additional cost, the 500 MW coal unit, which is in wide use on Ontario Hydro's system.

Figure 15–57 **Fuel Consumption 1989–2014** Median Forecast
Uranium Consumption

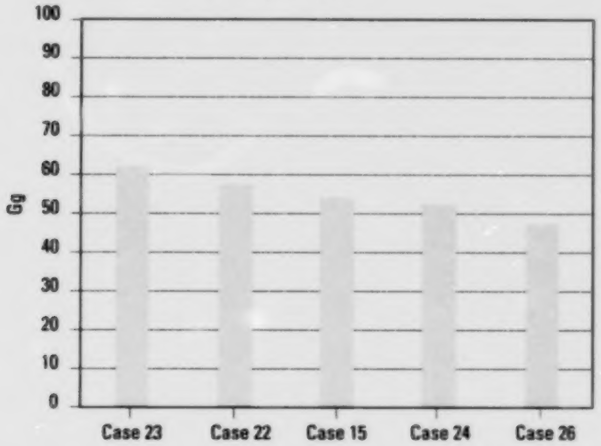
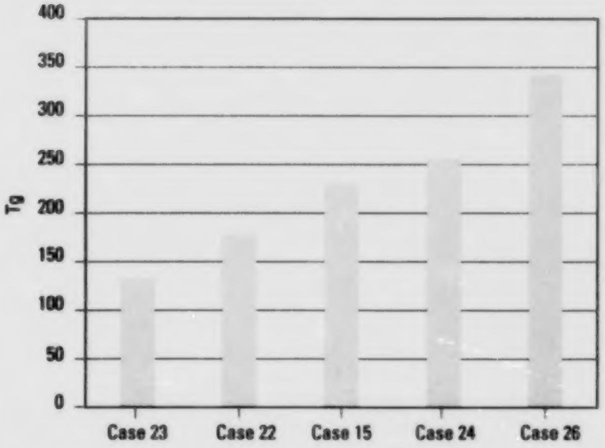


Figure 15–57 **Fuel Consumption 1989–2014** Median Forecast
Coal Consumption



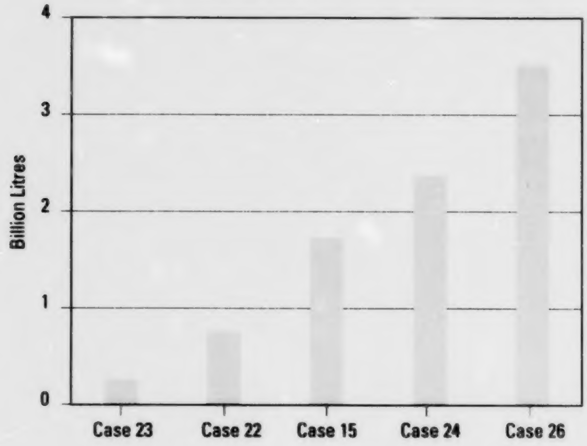


Figure 15–57 **Fuel Consumption 1989–2014** Median Forecast
Oil Consumption

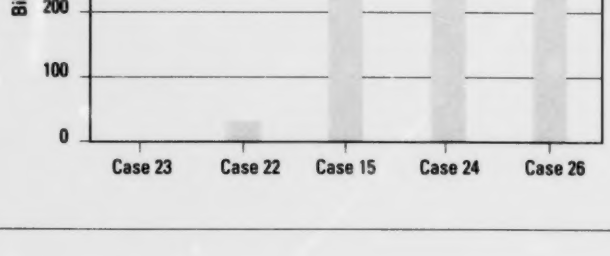


Figure 15–57 **Fuel Consumption 1989–2014** Median Forecast
Natural Gas Consumption

Disposal of Radioactive Waste

A radioactive waste disposal concept has been developed in Canada and in other countries with commercial nuclear power programs. The concept features an underground repository deep in stable rock formations. The repository concept will accommodate the nuclear fuel waste volume from all five Cases.

The repository site, which will be subject to environmental review and assessment, has not been selected.

The used fuel waste disposal concept, Figure 15–56, is expected to go into service after 2020. In the interim, Hydro plans to continue to store radioactive fuel in water filled bays or concrete containers at nuclear stations.

Resource Preference

Uranium is abundant and indigenous to Ontario and Saskatchewan. Coal is abundant and, as planned in the Cases, supplied from US sources. Natural gas and oil are less abundant, but are indigenous to Western Canada. There are wide variations in fuel use under the median forecast. These differences are particularly pronounced for natural gas and oil use under the upper forecast.

Fuel use under the median forecast is summarized in Figure 15–57.

Resource Smoothing

CANDU is a Canadian concept. A smooth program (see element 2.3 in the Demand/Supply Planning Strategy), retains the capability and lowers the cost as compared with a program with severe valleys and peaks. The fossil program is not so vulnerable, because it has a worldwide technology base. The Hydraulic Plan discussed in Chapter 12 is also a smoothed program.

Capacity Diversity

Supply I/S in Jan. 2014	Existing System (1993) GW	Existing System (1993) %	Case 23 GW	Case 23 %	Case 22 GW	Case 22 %	Case 15 GW	Case 15 %	Case 24 GW	Case 24 %	Case 26 GW	Case 26 %
Hydraulic	6.5	19.8	9.4	22.1	9.4	22.1	9.4	22.1	9.4	22.0	9.4	22.1
NUG-Purchases	0.3	0.9	1.5	3.5	1.5	3.5	1.5	3.5	1.5	3.5	1.5	3.5
Man. Purchase	0.0	0.0	1.0	2.4	1.0	2.3	1.0	2.3	1.0	2.3	1.0	2.4
Nuclear	14.2	43.0	25.3	59.7	21.8	51.2	20.1	47.2	16.5	38.8	11.2	26.5
Fossil	11.8	36.3	5.2	12.3	8.9	20.9	10.6	24.9	14.2	33.4	19.4	45.6
Total	32.8	100.0	42.4	100.0	42.6	100.0	42.6	100.0	42.6	100.0	42.5	100.0

Energy Diversity

Supply I/S in Jan. 2014	Existing system (1993) TWh	Existing system (1993) %	Case 23 TWh	Case 23 %	Case 22 TWh	Case 22 %	Case 15 TWh	Case 15 %	Case 24 TWh	Case 24 %	Case 26 TWh	Case 26 %
Hydraulic	35.7	23.5	40.8	19.1	40.8	19.1	40.8	19.1	40.8	19.1	40.8	19.1
NUG-Purchases	2.9	1.9	10.3	4.8	10.3	4.8	10.3	4.8	10.3	4.8	10.3	4.8
Man. Purchases	0.0	0.0	7.0	3.3	7.0	3.3	7.0	3.3	7.0	3.3	7.0	3.3
Nuclear	93.2	61.4	155.2	72.7	150.0	70.3	143.0	66.9	121.3	56.8	83.1	38.9
Fossil	20.0	13.2	0.3	0.1	5.5	2.5	12.5	5.9	34.2	16.0	72.4	33.9
Total	151.8	100.0	213.6	100.0	213.6	100.0	213.6	100.0	213.6	100.0	213.6	100.0

This makes the development more economic and, in particular, provides an orderly program in Northern Ontario.

Total System Diversity

All Cases rely on a number of supply options.

Figure 15–58 shows total system capacity and energy diversity, including the existing system of 1993 and the resulting supply diversity for the five Cases by 2014. Variations in diversity between Cases arise from the proportions of nuclear and fossil generation.

Flexibility – Load Forecasts

Flexibility is central to good planning because of uncertainties in capital costs, fuel prices, real interest rates, load forecast, load shapes, demand management and non-utility generation yields, maintenance costs, equipment performance and approvals for supply facilities.

Uncertainty in load forecast has the most significant impact on electricity system planning. Therefore, much of the analysis presented in previous sections dealt with how Cases respond to different load forecasts. The flexibility built into Cases to cope with uncertainty in load forecast provides the ability to deal with many other contingencies as well, provided that they do not occur along with higher load forecast.

Flexibility – Just-In-Time Commitments

Completion of new supply facilities involves pre-engineering, external approvals and acquisition. Timely approvals and completion of pre-engineering reduce lead times and increase flexibility.

To maintain reliable and economic supply, even if demand is above median forecast, enough approvals and pre-engineering are included in all Cases to meet the upper forecast. If the median or lower load forecast develop and the commitment is delayed, there is generally a small cost penalty.

Flexibility – Acid Gas

Flexibility to generate more electricity from coal and oil is crucial, because, in the short term, it is the only generation that can meet demand additional to forecast. Generally, hydraulic and nuclear are fully used and hence are not able to meet unexpected growth in load.

All Cases, except Case 26 in the upper forecast, meet the acid gas limits and provide the capability to produce an additional nine TWh per year without exceeding the limit.

Flexibility – Export Opportunities

If loads are lower than the median forecast, costs for Cases containing high capital cost, base load nuclear options can be mitigated. This is because nuclear energy can be exported to neighbouring utilities in the US that employ higher variable cost (fueling) generation.

Flexibility – Integrated Transmission Network

The high voltage transmission network within Ontario provides operating and planning flexibility. For example, if fuel costs change significantly or if demand changes significantly from forecast, then the preferred order of station operation may be shifted.

All Cases are designed to perform within the limitations of the integrated network.

Flexibility – Staged Commitments

Committing large multi-unit stations in one block may increase cost risks under low load forecast. Flexibility can be increased by committing only two units of a multi-unit station at a time.

This source of flexibility was not modelled in the analysis of Cases. The analysis also excluded the possibility of delaying or cancelling a station after construction had started. Thus the analysis of these Cases portrays costs and financial impacts that may be higher than if staged commitments are made.

Some options, such as the phased installation of IGCC stations, allow commitments to be spread out. To realize this flexibility, the combustion turbines must be placed on sites suitable for a coal-fueled IGCC station and approvals must be sought to allow use of coal or gas, with oil as a backup.

Flexibility – Short Lead-Time Options

Short lead-time options are required to respond to immediate needs arising from higher than expected loads and generating station problems. CTUs provide capacity in a short time, particularly if installed at existing fossil stations. CTUs convertible to CC in a short time mitigate energy costs.

All Cases include the installation of combustion turbines at existing generating sites. Because space limitation precludes conversion to combined cycle or IGCC, these CTUs are reserved for meeting requirements when no other option is feasible.

Flexibility – Tighter Air Emission Regulations

Cases 26 and 24 have less flexibility to meet tighter acid gas emission regulations, because they produce amounts close to the current limit. They exceed the CO_2 illustrative target.

Cases 15, 22, 23 have some flexibility to meet tighter air emission regulations, particularly Cases 22 and 23.

Flexibility – Delays In Approvals

Approval delays can have a significant impact on Cases which have high reliance on one generation type, i.e., Cases 23 and 26.

Cases 15, 22 and 24 are less vulnerable to approval delays because they contain a mix of major supply options. Case 24 is least vulnerable to the impact of approval delays because it has both nuclear and fossil in preparatory stages – if one is delayed, the other can fill the need.

Flexibility – Higher Fuel Prices

Cases 24 and 26 rely on coal and gas to a larger extent than Cases 15, 22, and 23. They are, therefore, more vulnerable to fossil fuel price increases.

All Cases retain the flexibility to convert the first phases of IGCC to either combined cycle to increase efficiency or to coal, if gas prices increase significantly.

Increases in uranium prices have low impact on the cost of nuclear generated electricity, i.e. doubling the uranium cost increases the cost of nuclear generated electricity by about 3 to 4%. Increases in coal price have a high impact on the cost of base load coal generation, e.g., doubling coal costs increases the cost of coal generated electricity by about 22%.

Historically, coal prices have been relatively stable, a trend that is expected to continue.

Oil and natural gas prices are higher than coal prices and are subject to more uncertainty in the long term.

Flexibility – Higher Interest Rates

Relative to Cases 24 and 26, Cases 15, 22 and 23, have greater use of high capital cost nuclear stations. As a result, they are more vulnerable to increases in interest rates. Cases 24 and 26 are less vulnerable, because they make greater use of lower capital cost fossil stations.

[illegible]

The five Cases presented in this chapter perform well in terms of reliability, safety and technical soundness. The remainder of this discussion presents the main advantages and disadvantages of each Case, and Hydro's judgement on their acceptability.

Case 26

Advantages

- It has the lowest impact on electricity prices from 2000 to 2009 and the lowest net borrowings over the plan period (Figures 15–52, 15–53).
- It has a more equal mix of fossil and nuclear energy, when the whole system is considered (Figure 15–58). Fossil energy will provide 34% of the electrical energy, and nuclear 39%.
- There are public concerns about nuclear safety and radioactive waste disposal. Case 26 features no new nuclear stations.

Disadvantages

- Higher 25-year plan cost than Cases 15, 22, and 24. The expected cost of Case 26 is $857 million (1989 present value) more than Case 15. There is a 97% probability of Case 26 being higher cost than Case 15. Costs to 2044 are $3,044 million higher than Case 15 (Figure 15–55).
- Meets current acid gas limits of 215 Gg, but does not provide a nine TWh margin under upper forecast (Figure 15–30).
- Under upper, median and lower load, Case 26 exceeds illustrative CO_2 targets of 24 Tg per year (Figure 15–36). Average annual CO_2 emissions from 2010 to 2014 are:

Lower forecast – 35 Tg per year
Median forecast – 60 Tg per year
Upper forecast – 75 Tg per year

- Does not have the flexibility to respond to tighter acid gas regulations or CO_2 regulations.
- Has the lowest Ontario goods and services content and the lowest Canadian content.
- Poor balance of trade relative to other Cases.
- Vulnerable to approval delays.

Conclusion

Case 26 is judged to be unacceptable, because of high costs, environmental effects of heavy reliance on fossil generation, and vulnerability to approval delays.

Case 23

Advantages

- Lowest acid gas and CO_2 emissions. Meets current acid gas regulations and illustrative CO_2 target (Figure 15–36).
- High flexibility to adapt to tighter air emission requirements (Figure 15–30).
- Highest Ontario and Canadian goods and services content.
- The most favourable balance of trade.
- Responds to ongoing public concern about acid gas emissions and emerging public concern about the contribution of CO_2 to the greenhouse effect.

Disadvantages

- Highest 25-year plan cost. The expected cost of Case 23 is $2,097 million (1989 present value) higher than Case 15 (Figure 15–51). Costs beyond the study period are $5,074 million higher than Case 15 (Figure 15–55).
- Highest public concern regarding nuclear safety and radioactive waste disposal.
- Vulnerable to approval delays.
- Highest impact on net borrowing from 1993–2001 period and highest impact on electricity prices from 1997 to 2009 (Figures 15–52, 15–53).
- Too much reliance on one option, in this Case, the nuclear option. Nuclear capacity increases from 43% in 1993 to 60% in 2014, nuclear energy increases from 61% in 1993 to 72% in 2014. Fossil energy declines to less than 1% (Figure 15–58).

Although Ontario's nuclear facilities have operated reliably, it is beneficial to maintain reasonable diversity in generation type.

Conclusion

Case 23 is unacceptable, because of high costs, heavy reliance on one option, and vulnerability to approval delays.

Cases 15, 22 & 24 – Acceptable

Overall, Cases 15, 22, & 24 are judged to better satisfy the planning criteria, with particular strengths in the following areas:

- long-term cost, borrowing and electricity prices;
- acid gas emissions;
- acid gas flexibility;
- CO_2 emissions;
- radioactivity;
- Ontario/Canadian content;
- balance of trade; and
- diversity.

Accordingly, alternative Cases 15, 22 and 24 are acceptable as Candidate Major Supply Plans.

SELECTION OF THE PROPOSED MAJOR SUPPLY PLAN

None of the three Candidate Major Supply Plans is best in all respects. The following compares the three Candidate Major Supply Plans and identifies the Major Supply Plan proposed by Ontario Hydro.

25-year Plan Costs: Plan 15 has the lowest 25-year plan cost. The present value expected cost of Candidate Plan 22 is $365 Million higher. Candidate Plan 24 is $187 Million higher (Figure 15–51).

Costs beyond 2014: Plan 15 has the lowest long-term cost. The present value costs of Plan 22 is $938 Million higher, and Plan 24 is $712 Million higher (Figure 15–55).

Electricity Price and Borrowings: Plan 24 has the lowest electricity prices from 2000 to 2009 and lowest net borrowings from 2003 to 2007. In the longer term, electricity prices for Plan 15 will be lower (Figure 15–52, 15–53).

Acid Gas Emissions: Plan 22 has the lowest acid gas emissions. Plan 15 has the next lowest, Plan 24 has the highest. Under median load, from 2010 to 2014, annual average emissions for Plan 22 are 90 Gg; Plan 15, 135 Gg; and Plan 24, 150 Gg (Figure 15–30). The flexibility to meet tighter regulations is highest for Plan 22, lowest for Plan 24.

CO_2 Emissions: The illustrative target considered by the Canadian ministers, 80% of 1988 levels, corresponds to 24 Tg per year for Ontario Hydro by 2005. Plan 22 has the lowest CO_2 emissions. It meets the illustrative target under lower and median load forecasts and almost meets the target under the upper forecast. Plan 15 meets the target under lower and median forecasts, and, except from 2005 to 2009, meets the upper. Plan 24 does not meet the illustrative target under median and upper load forecasts.

Balance of Trade: In the longer term (2040), Plan 22 has the most favourable balance of trade, $1 Billion (1989 present value) over Plan 15. Plan 24 has least favourable balance of trade, about $300 million (1989 present value) less than Plan 15.

Radioactivity concerns: One dimension of social acceptance is an ongoing public concern with respect to reactor safety and radioactive waste disposal. Plan 22 has the most new nuclear stations, Plan 24 has the least.

Diversity: There are no major changes in diversity between the existing system and the future system with any of the three Plans.

Resource Smoothing: Under median and upper forecasts, Plans 15, 22 and 24 acceptably maintain the capability to design, manufacture, construct and operate nuclear and fossil generation. Under the lower load forecast, there is a significant interruption in the nuclear program, which would adversely affect maintaining the CANDU option.

Approval Delays: Plan 24 is less vulnerable to the impact of approval delays than the other Plans.

Conclusion

Considering all of the above comparisons, Candidate Major Supply Plan 15 is selected the Proposed Major Supply Plan. It is judged to be the best plan, because it offers good environmental characteristics, good diversity, good flexibility and is the lowest cost.

Alternative Major Supply Plan 22 (Higher Nuclear) and Alternative Major Supply Plan 24 (Higher Fossil) are acceptable alternative plans.

Chapter 3
Basic Load Forecast

Chapter 4
The Existing System

Chapter 5
Requirement for Demand/Supply Options

Chapter 6
Costing Concepts and Avoided Costs

Chapter 7
The Demand Management Plan

Chapter 8
The Non-utility Generation Plan

Chapter 9
The Primary and Firm Load Forecasts

Chapter 10
Rehabilitation Plan

Chapter 11
Requirement for New Supply
Chapter 12
The Hydraulic Plan
Chapter 13
Requirement for Major Supply
Chapter 14
Major Supply Options
Chapter 15
Major Supply Plans
Chapter 16
Avoided Cost Determination
Chapter 17
Demand/Supply Plans
Chapter 18
Action Plans

16 AVOIDED COST DETERMINATION

This Chapter shows how avoided costs are determined and provides examples of the avoided costs associated with the three candidate Major Supply Plans developed in Chapter 15.

Chapter 6 describes costing concepts Ontario Hydro uses including avoided cost. Avoided costs are the supply costs avoided when any demand or supply option is substituted for an equivalent part of a demand/supply plan. The avoided cost concept described in Chapter 6 is applied in this Chapter.

For each demand or supply option, the avoided cost can be estimated to determine if the option is economic. The avoided cost estimate varies with each specific proposal. For example, a NUG proposal for 80% base load application will have a much lower avoided cost expressed in cents per kWh than a NUG proposal for 10% peak load application.

The Demand Management Plan, the NUG Plan, and the Hydraulic Plan, depend upon avoided cost. An option is economic if the cost of the proposed option is equal to or less than the avoided cost. Also,Major Supply Plans depend uponthe contribution from the Demand Management, NUG and Hydraulic Plans. All of these plans are brought together when developing demand/supply plans.

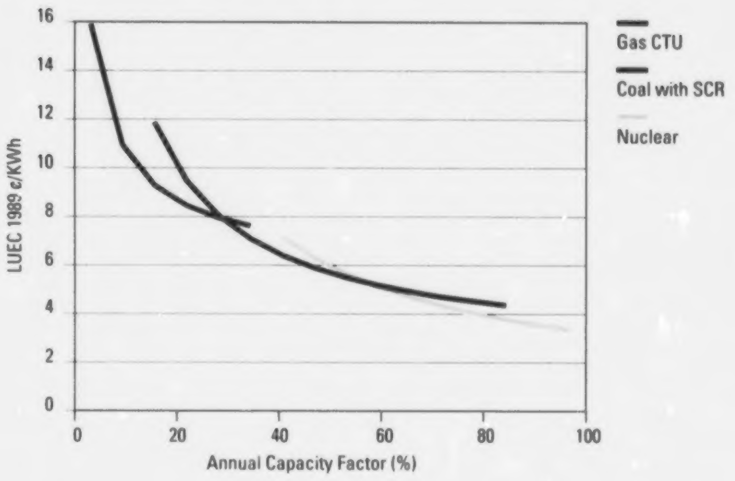
Hydro also uses avoided cost estimates to determine whether or not proposed modifications to the existing system are economic. The topics discussed in this Chapter include the following:

- A simplified method based on LUEC estimates – to determine approximate avoided costs.
- A full simulation method – to determine avoided costs more accurately is described.
- A system incremental cost method – a practical way to determine avoided costs for many small and intermediate size options. System Incremental Costs include credits and adjustments for factors such as reliability, transmission, and acid gas control.
- The sensitivity of System Incremental Costs to variation in factors such as load growth, candidate plans, fossil estimates, and nuclear estimates.
- Avoided costs are specific – they must be determined for each proposal.
- Examples of avoided costs – for Demand Management, NUGs, and Hydraulic Generation showing how avoided costs vary for time period, capacity factor, dispatchability, and the Candidate Plans.
- The feedback of avoided costs to the Demand Management, NUG and Hydraulic Plans.

Simplified Avoided Cost Method

The cheapest supply option to meet low capacity factor load is gas-fueled Combustion Turbine Units. The avoided cost of such low capacity factor generation includes capital, OM&A, and fueling costs. For intermediate capacity

Figure 16–1 **LUEC Versus ACF** In–Service Year 2002



factor loads, say between 20 and 50%, the least cost supply option, with a well balanced generation mix, is coal-fueled generation. The avoided cost again consists of the capital, OM&A, and fueling costs, including the cost of acid gas emission controls. For high capacity factor loads, the least cost supply option is new nuclear generation. These conclusions are based on the LUEC estimates presented in Chapter 14.

Figure 16–1 shows the LUEC estimates in cents per kWh for Combustion Turbine Units, new CSC coal-fueled stations and new nuclear stations. It shows the dependency of the LUEC estimates on capacity factor. It shows that the least cost supply option for low capacity factor is gas-fueled Combustion Turbine Units, and that for high capacity factor, the least cost supply option is nuclear.

This simplified method of determining avoided costs is only good for stations with complete dispatch and for a system with an optimal mix of base, intermediate and peaking generation. With a real system and with many of the options there are complicating factors. Consider the following three examples.

A low capacity factor NUG option can be purchased in place of planned peaking CTUs. If the NUG is dispatchable it can be used to meet peak loads as needed. If, however, the NUG is not dispatchable and operates randomly through the year, it will not have a full capacity value and can only be credited with displacing the average fuel mix.

The second example relates to Demand Management. Increases in the efficiency of air-conditioning facilities reduces load only during the summer. Generation capacity requirements are dictated by winter peak loads, so such improvements can't be credited with capacity savings but can be credited with fuel and operating savings.

The third example relates to time constraints. Let us assume there is a load growth well above the median forecast. In the short term, there may be insufficient time to install the lowest cost supply option (e.g., nuclear for base load). This will increase the avoided cost. A high capacity factor NUG may avoid higher cost options until nuclear can be built.

Because of these and other complicating factors, the simplified LUEC method cannot be used in all cases. A more rigorous method is needed to ensure fairness and consistency in evaluating options. However, the LUEC simplified method provides a useful check for the results of the full simulation and system incremental cost methods.

Full Simulation – Avoided Cost Method

A more rigourous method of determining avoided costs is the full simulation process. This involves calculation of the total cost of a candidate demand/supply plan including its impact on the existing system. Total system simulations are performed, including the system expansion life cycle costs of all elements of the plan, appropriately allocated to the study period as described in Chapter 6.

Next, the total cost of the plan under alternate assumptions is determined. An example is the economics of a proposed NUG option which would have an installed capacity of 500 MW and an annual capacity factor of 80%. The candidate plan would be modified to include the proposed option. The cost of the modified supply plan (excluding the cost of the proposed NUG option) is lower because Hydro can reduce operations at existing facilities and reduce the amount of new capacity additions.

The difference in cost between the original candidate plan (without the proposed NUG option) and the modified plan (incorporating the option but excluding the cost of the NUG) is the avoided cost of the NUG option. This has to be compared to the cost of purchasing the power and energy from the NUG facility. If the avoided cost is greater than the cost of purchasing the output of the NUG option the NUG is economic.

System Incremental Costs

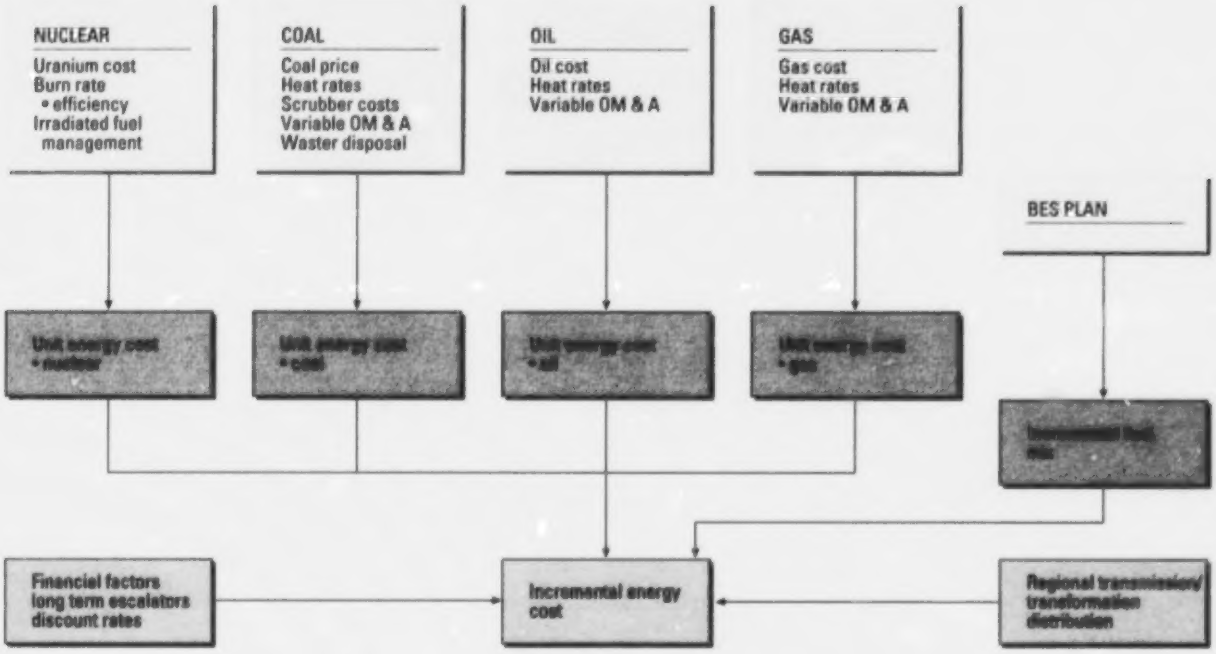
Given the large number of demand management, NUG, hydraulic and other options to be evaluated, the full system simulation method would be too expensive and too slow. The system incremental cost method provides acceptable, accurate results with manageable effort.

This method is usually used for small and intermediate options. The use of system incremental costs improves the accuracy and stability of avoided cost calculations. The effect of each small change is hard to identify in a big system. However, the incremental costs credit each small change, assuming that many small changes will, in total, avoid the need for a major generating station.

System incremental costs are usually divided into two components. The first, incremental energy costs, are all the extra costs, including operating and fueling costs, that the power system incurs when it has to meet an increased energy demand. The second component, incremental power costs, are defined as the net cost of new capacity, or the cost to return

Avoided cost methodology helps determine whether efficiency improvements in home or industry are cost effective.

Figure 16–2 **Cost of Incremental Energy**


NUCLEAR
Uranium cost
Burn rate
• efficiency
Irradiated fuel management
COAL
Coal price
Heat rates
Scrubber costs
Variable OM & A
Waster disposal
OIL
Oil cost
Heat rates
Variable OM & A
GAS
Gas cost
Heat rates
Variable OM & A
BES PLAN
Unit energy cost • nuclear
Unit energy cost • coal
Unit energy cost • oil
Unit energy cost • gas
Incremental fuel mix
Financial factors long term escalators discount rates
Incremental energy cost
Regional transmission/ transformation distribution

mothballed capacity to service, to meet increased peak power demand. It is the cost of meeting an increase in load at the time of peak demand, but at no other time.

A few computer simulations of the full system, with and without demand and supply plan changes, give considerable information – enough to establish system incremental costs of power and energy. The incremental power and energy costs are determined for each year of the 25 year study period. Incremental energy costs are determined for four time periods in each year – winter peak, winter off-peak, summer peak and summer off-peak. The avoided cost of a particular option can be readily determined by combining the individual components of system incremental costs for power and energy applicable to that option.

Incremental Energy Costs

Incremental Energy Costs – Components and Factors

Figure 16–2 shows the components and factors that go into the estimate of incremental energy costs. These are discussed below. All costs are expressed in 1989 dollars.

Incremental Energy Cost – Fuel

Four primary energy forms are expected to supply incremental energy. They are uranium, coal, gas and oil. Water, while used for generation, is not expected to be incremental energy. It will be fully used.

- Incremental uranium fuel costs, including fuel fabrication, are forecast to be $100 per kg (U) in 1989, $121 in 2000 and $141 in 2014. Adding irradiated fuel storage and disposal costs results in a total unit fueling cost of 0.34 cents per kWh in 2000.
- Most oil used is residual oil and burned at the Lennox station. Residual oil price is forecast to increase from $4.05 per GJ in 1989 to $6.26 per GJ in 2014. The Lennox station is forecast to have a unit fueling cost of 6.10 cents per kWh in 2000.
- Natural gas prices are currently $2.97 per GJ. They are forecast to rise to $4.5 per GJ by 2000 and $5.38 per GJ by 2014. The resulting unit energy costs for gas-fueled CTU's is 5.5 cents per kWh in 2000.
- In 1989, incremental coal for CSC stations with scrubbers costs $1.73 per GJ based on 2% sulphur U.S. coal. It is forecast to remain at about this level, resulting in fueling costs of around 1.76 cents per kWh in 2000.

Incremental Energy Cost – OM&A

In addition to the cost of fuel, there are operating, maintenance and administration costs (OM&A) involved in running generating stations.

The OM&A costs for existing fossil stations have fixed and variable components.

The variable OM&A for existing coal stations is 0.11 cents per kWh. This, when combined with the fuel cost, results in a unit energy cost of 1.87 cents per kWh in 2000.

The fixed OM&A for existing fossil stations and all OM&A for other stations including new fossil stations is included in the incremental power costs.

Incremental Energy Cost – Acid Gas

Ontario Hydro must limit its acid gas emissions to 215 Gg per year. For increased production of energy from fossil stations, the plan provides that this limit is never exceeded. The system incremental cost of power and energy includes the cost of sufficient acid gas controls to completely eliminate additional acid gas emissions due to the additional electricity produced. The acid gas is limited by scrubbers, lower sulphur fuels, modifications and non-fossil generation.

Capital, fueling and operating costs for acid gas reduction add about 0.56 cents per kWh to the cost of coal generated electricity in the mid to late 1990s. For new CSC coal-fueled generating stations, these costs are included in the incremental power costs.

Incremental Energy Cost – Exports

Generally, Ontario Hydro does not consider exports in its long term planning. However, most of the time that surplus nuclear and hydraulic energy is available, it will be possible to sell it on a short term, interruptible basis to US utilities to displace fossil fueled generation. If this energy is used instead to supply an increase in Ontario load, the sale to the US will be reduced and the value of the energy will be the lost revenue from the sale. The effect is to increase avoided cost.

The "value" of uranium-generated electricity increases from 0.3 cents per kWh to around 0.8 cents per kWh. The 0.8 figure assumes that not all of the surplus energy can be exported.

Incremental Energy Costs – Transmission and Distribution

System incremental energy costs are at the generator level. Some options, including demand management options, reduce transmission and distribution losses.

Transmission and distribution losses vary between 5 and 10% depending on location, and increase the avoided energy costs.

Incremental Energy Costs – Derivation

Incremental energy costs are determined by comparing the total system operating costs of a base plan, with the same plan when the demand is increased by about 1% (200 MW) in the analysis of the plans. The supply program is left unchanged. The demand increment is constant year round. The total costs in each case are determined by computer simulations. The impacts in different years and in different times of the year are determined. The difference in costs, expressed in cents per kWh, is the system incremental energy cost for the plan, and for the year and time period.

As explained in Chapter 6, the cost of producing electricity varies with the time of day and year. During winter and summer peak demand periods, the costs are higher because Hydro must utilize more expensive generation to meet customers' demands. Hydro's incremental energy costs are therefore dependent on the timing of the change the proposed option makes in Hydro's own operations. If a non-utility generation project or demand management program makes it possible for Hydro to reduce its own operations during peak demand periods, its value to the system will be higher than a project only capable of meeting electricity demands in off-peak periods.

Incremental energy costs are derived for each year of the study period. Within each year, four time periods are used. The winter peak period, 7 a.m. to 11 p.m. of working week days in the months October to March; the winter off-peak period; a summer peak period, 7 a.m. to 11 p.m. on working weekdays in the remaining months; and a summer off-peak period. These periods correspond to different operating levels and costs. They are also used for Time-of-Use rate periods.

Figure 16–3 shows the variation in the system incremental fuel mix for the four periods and the average over the year. The charts assume that there are no exports. Each bar on the annual figure is divided into three segments. The lowest segment indicates the proportion of time that there is unutilized nuclear generation and additional load will be met by increased use of nuclear plant i.e., nuclear is on the margin. The middle segment shows the proportion of time that coal is on the margin. The top segment shows the proportion of time that oil and gas are on the margin. In the year 2000, nuclear is on the margin 11% of the time, and almost all of the remaining time, coal is on the margin. Nuclear is on the margin about 15% on average through the study period. Oil and gas noticeably increase after 2008.

The system incremental energy costs are derived by taking the incremental mix of fuels and their costs, as illustrated in Figure 16–4. Using the year 2000 as an example, the components of the four incremental fuel types, the total energy cost, and the proportion of time each is incremental in the year is shown.

The contribution of coal to the average incremental cost is determined by taking the unit cost of coal fuel of 1.9 cents/kWh and adding the scrubber adder of 0.6 cents/kWh to account for acid gas control costs. The total

Figure 16–3 **Incremental Energy Proportions by Fuel Type**

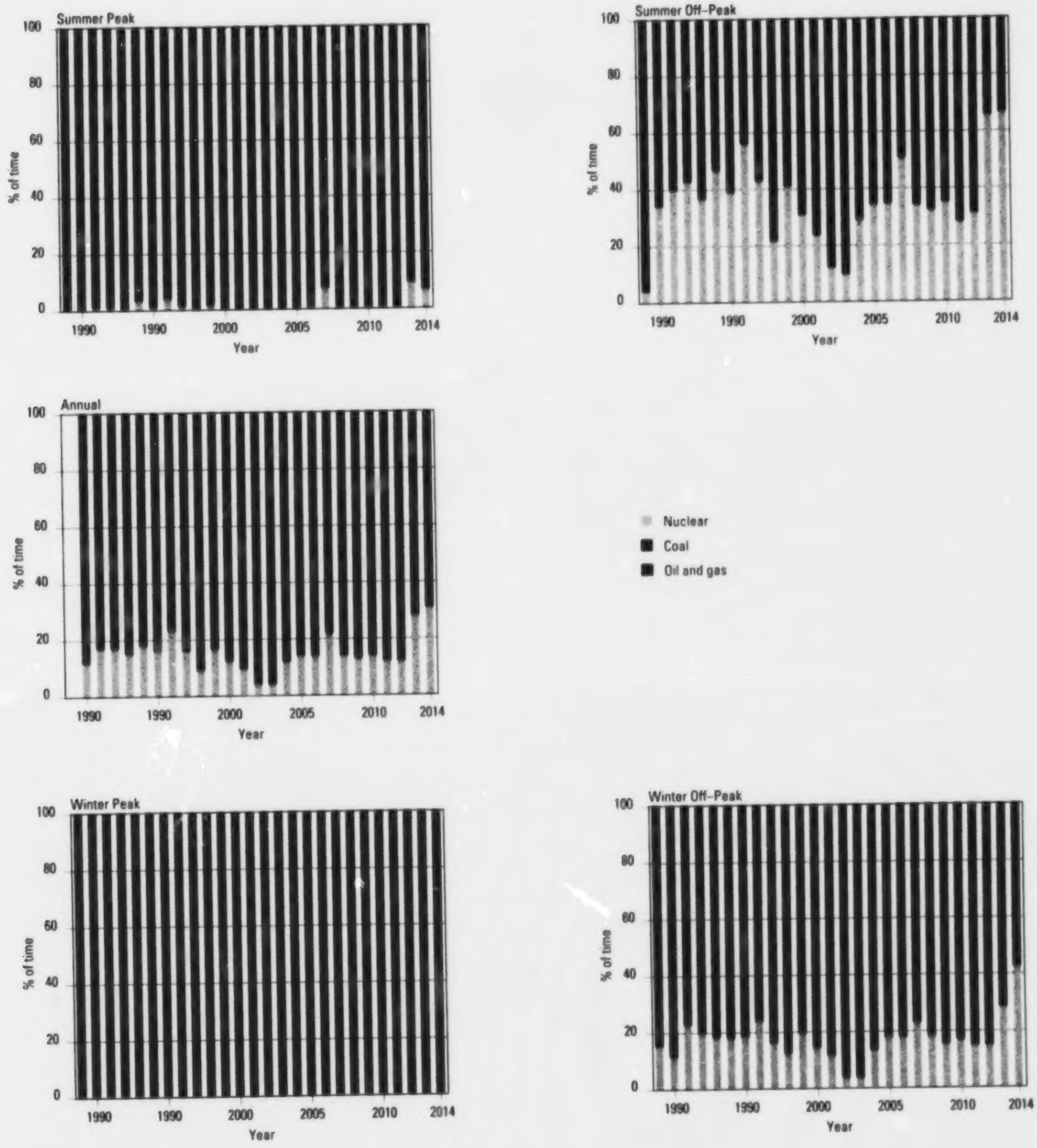


Figure 16–4 Determination of average incremental cost year round load 2000 median load growth

Incremental energy production from	unit cost	adj for exports	Cost (¢/kWh) scrubber adder	Total	Incremental (fuel mix %)	Contribution to average Incremental ¢/kWh
Coal	1.9	N/A	0.6	2.5	89	2.2
Oil	6.1	N/A	0.0	6.1	0	0.0
Gas (CTU)	5.5	N/A	0.0	5.5	0	0.0
Nuclear	0.3	0.5	0.0	0.8	11	0.1
Average incremental cost (¢\kWh)						2.3

cost of 2.5 cents/kWh is multiplied by 0.89 to account for the 89% probability of coal being on the margin. Oil and gas contribute a negligible proportion to incremental fuel mix in 2000 while nuclear costs including the cost of exports contribute 0.1 cents/kWh based on a total cost of 0.8 cents/kWh and being on the margin 11% of the time.

Incremental Power Cost

Incremental Power Cost – Components and Factors

Incremental power costs are the net costs of new capacity, or the costs to return mothballed capacity to service, to meet increased demand. Incremental power costs are the costs of meeting an increase in load at the time of annual peak demand, but at no other time.

Incremental power costs are seldom used in isolation – they are combined with incremental energy costs to evaluate options which save both power and energy. Figure 16–5 shows the components and factors that go into the estimate of incremental power costs.

Incremental Power Cost – Gross Capacity

The capacity costs of new coal and gas-fueled stations include:

- design, construction and training;
- scrubbers and/or other environmental control facilities;
- capacity-related OM&A costs; and,
- transmission incorporation costs.

The gross capacity cost of additional combustion turbine units is $49 per kW per year based on the first phase of an IGCC.

The gross capacity cost of an additional CSC coal-fueled station, including acid gas control facilities, is $166 per kW per year.

The gross capacity costs for nuclear generation include:

- design, construction & training,
- heavy water,
- provision for decommissioning,
- provision for retubing,
- capacity-related OM&A costs; and
- transmission incorporation costs.

The gross capacity cost of additional nuclear plant is $205 per kW per year.

Incremental Power Costs – Net Capacity

Adding generation to meet an increase in demand alters the generation mix and usually lowers the cost of meeting energy requirements. There is a reduction for CSC coal-fueled units and a larger reduction for CANDU nuclear units. However, there is no reduction for combustion turbine units.

The net capacity cost is the gross capacity costs less the credit for reduced energy costs.

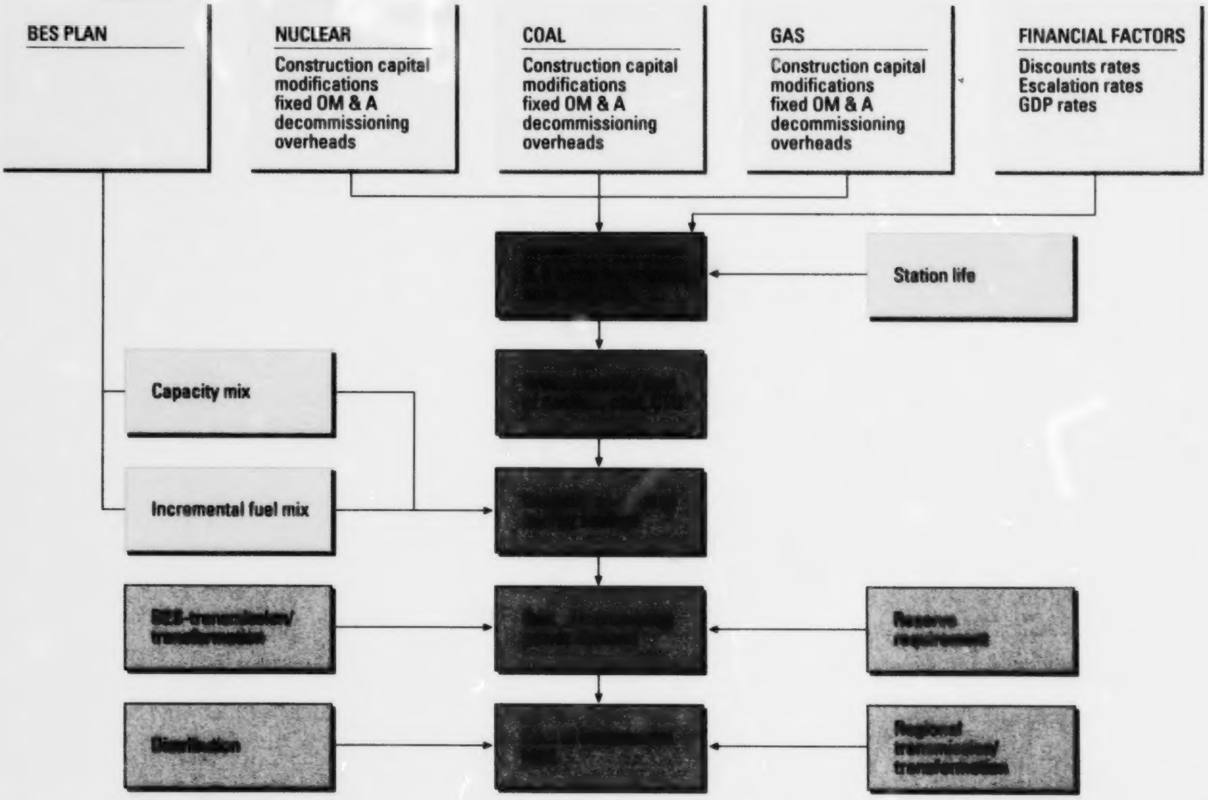
The energy credit depends on details of the plan and varies from year to year. That it can be substantial can be seen from the following example. A CANDU station with a fueling cost of 0.3 cents/kWh saves 2.2 cents/kWh when it displaces coal-fueled CSC energy at 2.5 cents/kWh. At 80% annual capacity factor, this energy credit is equal to a reduction in capacity cost of $155 per kW per year.

Allowing for the energy credit the gross capacity cost of nuclear (new site) is reduced from $205 per kW per year to a net cost of $50 per kW per year.

For a plan with the lowest cost mix of generation types, the cost of capacity net of energy savings should be equal for all options that are in the plan.

The proposed major supply plan does not include new coal-fueled stations in the study period.

Figure 16–5 **Cost of Incremental Power**


BES PLAN
NUCLEAR
Construction capital modifications fixed OM & A decommissioning overheads
COAL
Construction capital modifications fixed OM & A decommissioning overheads
GAS
Construction capital modifications fixed OM & A decommissioning overheads
FINANCIAL FACTORS
Discounts rates
Escalation rates
GDP rates
Station life
Capacity mix
Incremental fuel mix
BES-transmission/ transformation
Reserve requirement
Distribution
Regional transmission/ transformation

Incremental Power Cost – Reliability Reserve

Additional generating capacity is needed to provide a reserve margin to maintain reliability. When modifying the plan in response to a change in demand, this is allowed for.

The incremental cost of power is multiplied by 1.24 to reflect the need for 24% reserve.

Incremental Power Cost – Transmission and Distribution

System incremental power costs are at the generator level. For options that reduce customer loads allowance must be made for the costs of building and maintaining the transmission.

Bulk transmission costs add $ 19 per kW per year.

Distribution facilities are also required to meet increases in customer demand. Depending on the location of the increase in demand, Ontario Hydro or a municipal utility will need to advance facilities.

On average, distribution avoided costs are a levelized $20/kW per year.

Losses in the transmission and distribution facilities also have to be allowed for.

Losses vary between 5% to 10% depending on the delivery point and increase the incremental power costs.

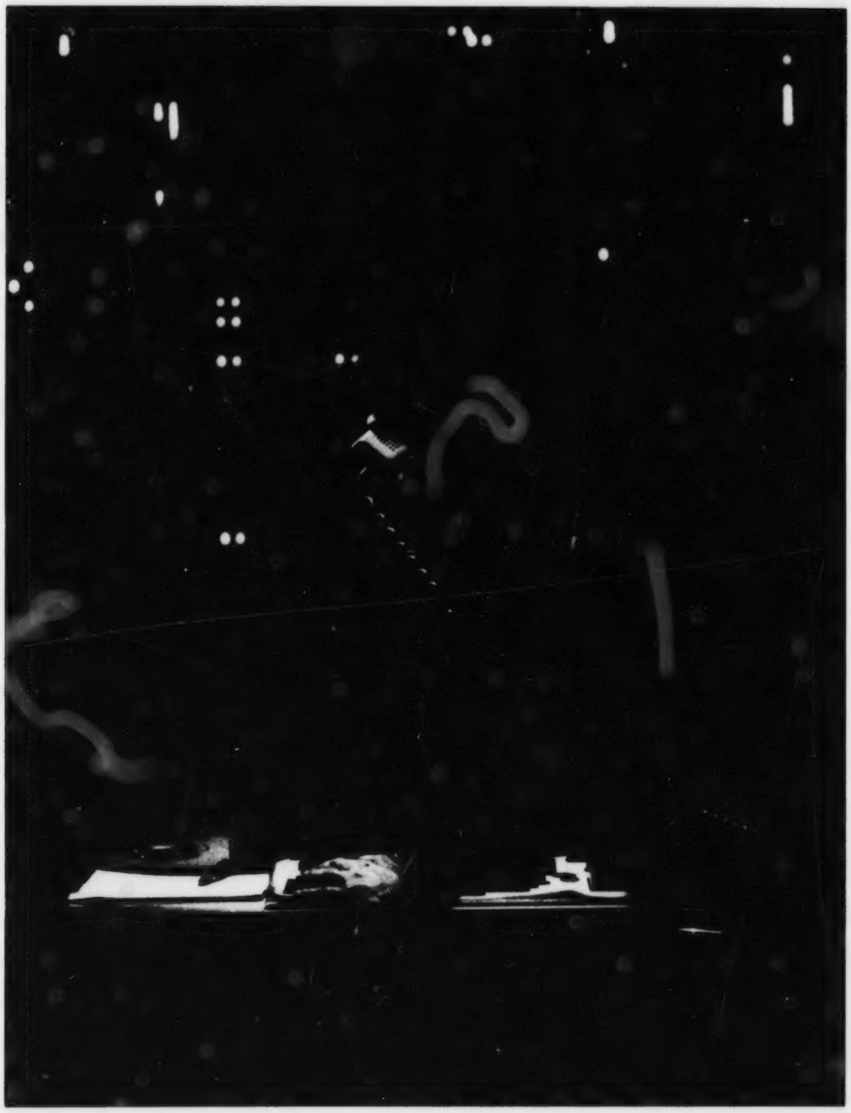
The avoided costs of options implemented in the next decade are not sensitive to which candidate plan is used.

Incremental Power Cost – Short Term Considerations

Demand management, non-utility generation and, hydraulic options meet capacity requirements during most of the 90s, and no fossil and nuclear generation is planned to come into service under the median forecast. However, without these options additional supply capacity would be required. For this reason, all of the planned demand management, non-utility generation and hydraulic generation is credited with a capacity value.

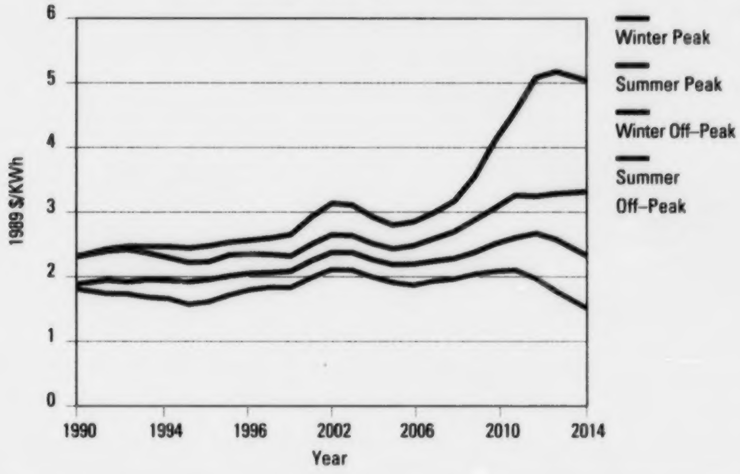
Incremental Power Costs – Derivation

Incremental Power Costs are determined by comparing the total system costs of a base plan and the same plan with about a one percent increase (200 MW) in the load meeting capability while keeping the demand constant. Computer simulations are necessary to derive the net capacity costs.



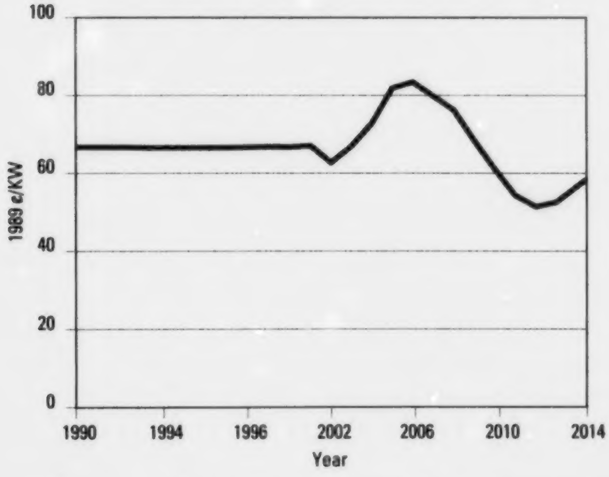
Hydro's Richview control centre. The value of a non-utility generation source is higher if it can produce power when needed.

Figure 16–6 **Expected Incremental Power & Energy Costs of Proposed Plan***
Incremental Cost of Energy



* Exclude distribution and non–generation related transmission costs, as well as transmission and distribution losses.

Figure 16–6 **Expected Incremental Power & Energy Costs of Proposed Plan***
Incremental Cost of Power



*Exclude distribution and non–generation related transmission costs, as well as transmission and distribution losses.

Avoided costs are sensitive to load forecast.

System Incremental Costs – Expected

Figure 16–6 shows expected incremental costs for the proposed major supply plan, for each year 1990 to 2014. They are "expected" in the sense that the system incremental costs are calculated for the upper, median and lower load forecasts, and the results have been weighted by factors of 0.2, 0.6, and 0.2 respectively. These proportions assume that the upper load forecast which is at the 90% point on the probability distribution (i.e., has a 10% chance of being exceeded) is representative of all loads between the 80% and 100% points on the distribution. Similarly the lower load forecast is at the 10% point and is considered representative of the 0 to 20% range. The median is considered representative of the remaining 60%. Prior to the need date for major supply, the incremental power costs include an allowance for capacity based on CTUs, and incorporating transmission. These costs are for changes in demand at the generation level, and exclude costs associated with distribution and bulk transmission. The effect of losses and transmission and distribution costs has to be added as appropriate. As previously stated, these system incremental costs only apply for small and intermediate changes.

Figure 16–7 **Sensitivity of Avoided Cost to Candidate Plan**
Increment Cost of Power and Energy at 100% ACF

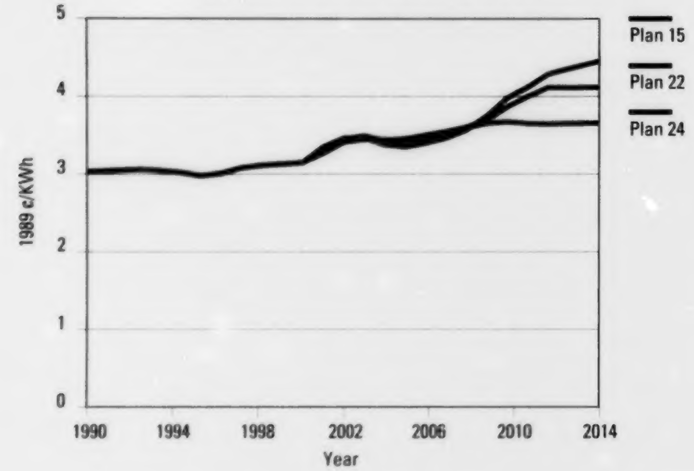
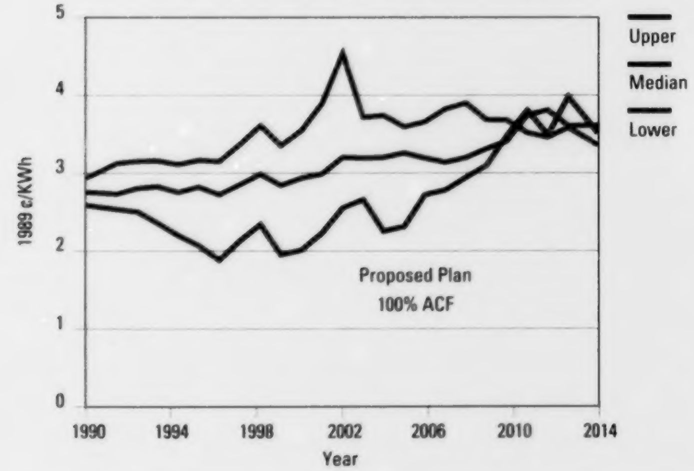


Figure 16–8 **Sensitivity of Avoided Cost to Load Growth**
Incremental Cost of Power and Energy at 100% ACF



For years beyond the study period, the average of the last five years is used.

Avoided Cost Sensitivity

Avoided Cost Sensitivity – Alternative Candidate Plans

The system incremental cost method can be used to calculate avoided costs for a specific option for a specified plan. An analysis has been done to determine the sensitivity of avoided costs for the three Candidate Demand/Supply Plans. The example selected is a constant year-round demand increment (100% ACF), Figure 16-7. There is no difference up to 2000. Beyond this, the differences grow to 25% by 2014.

Avoided Cost Sensitivity – Load Forecast

Figure 16–8 shows the system incremental costs for a constant demand, year by year for the period 1990 to 2014, for the Proposed Major Supply Plan under upper, median and lower load forecasts. The costs are higher for the upper forecast, and lower for the lower forecast. The maximum difference is about 25% around the year 2000. Thereafter the costs converge to a common long term value as Hydro adjusts to the actual load growth.

Avoided costs are sensitive to load forecast until system development can be adjusted to accommodate the actual load growth trend.

Avoided Cost Sensitivity – Supply Option Estimates

System incremental costs, as well as being sensitive to load forecast and plan, are also sensitive to the cost of the supply options themselves.

Ontario Hydro developed median estimates for the CANDU and fossil generation options together with a confidence band for the accuracy of the estimates. The typical confidence band was +20% to -15% of the median cost estimate, with an 80% chance that the costs will fall between these values. The avoided costs vary directly with the cost estimates for the major supply options.

Specific Options – Avoided Cost Determination

In determining avoided costs of options, Hydro uses system simulations or system incremental costs as appropriate. Hydro also looks at the specific and general transmission and distribution impacts.

Each demand management and non-utility generation project will have a different impact upon the electricity system.

For example, an insulation program for electrically heated homes may enable Hydro to reduce power production during winter months. The system cost savings from this type of demand management program are more than from a program that is only capable of reducing power consumption during summer periods, such as higher efficiency air-conditioning.

Using system incremental costs, the value of a program's energy savings are determined by multiplying the amount of energy saved in each of the four demand periods by the corresponding period's incremental energy cost.

In addition, if a program reduces load during the winter peak period, the program is assigned credit for Hydro's full incremental power costs.

The energy savings of the program are combined with the program's power savings to determine the total avoided costs.

The construction costs of new station is a key component in determining avoided costs.

The avoided cost of NUG options implemented in the next decade are not very sensitive to which Candidate Plan is used.

The lifecycle avoided costs can then be compared (on a present value basis) with the total cost of the insulation program. If the program's costs are less than the avoided costs, the program is considered economic for Ontario Hydro and its customers. This is the Total Customer Cost test that is described in Chapter 6.

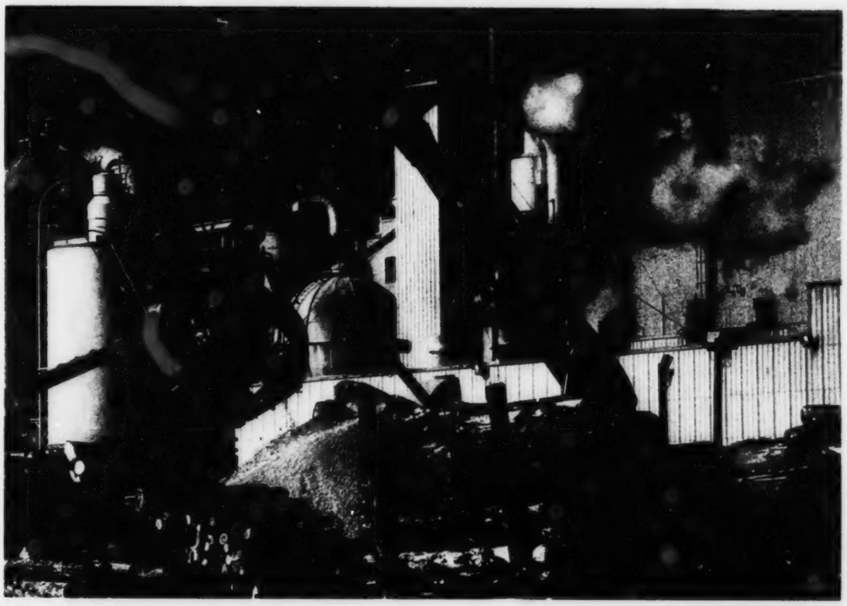
Avoided Cost Examples

This section presents illustrative avoided costs for some assumed NUG projects.

In practice every individual option requires a project specific evaluation which considers the individual characteristics of the option.

This section will show the impact of different assumptions on three parameters, energy production as characterized by annual capacity factor, timing and dispatchability.

In addition, avoided costs examples are given for demand management and hydraulic generation.



Cogeneration for wood products

The avoided costs quoted are based on the weighted average of the results from the upper, median and lower load forecast. They are all in 1989 dollars.

The avoided costs include a credit prior to the need date for capacity (CTUs), and transmission.

Avoided Cost Example – Non-Utility Generation

Figure 16–9 shows the illustrative avoided costs of a non-utility generator. The levelized avoided costs are shown for NUGs with an in-service period of 1994–2014 and a range of capacity factors (10%, 40% and 80%). A winter peak availability of 90% is assumed.

The costs are presented in levelized cents per kWh and in dollars per kW installed. The latter is the present value of the option over its life. These are alternative representations of the avoided cost – they are not additive.

The costs are presented for the Proposed Major Supply Plan 15 and the two Alternative Major Supply Plans 22 and 24.

The NUG avoided costs include transmission associated with the incorporation of generation. Other transmission benefits of NUGs are treated on a case-by-case basis.

The avoided cost, in Plan 15, for the 80% ACF, dispatchable NUG, in service between 1994 and 2014, is 3.4 cents per kWh, comparable to the LUEC of a nuclear station, as shown in Figure 16–1. This shows consistency between the simplified and incremental cost methods.

Comparing the results for the three candidate plans, the avoided cost of NUG options implemented in the next decade are not very sensitive to which Candidate Plan is used.

For the low capacity factor NUG the avoided cost goes up to 10.0 cents/kWh. Because it is saving less energy, its total value drops to 1080 $/kW (from 2920 $/kW).

Figure 16-9 **Avoided Costs Depend on Capacity Factor**
Avoided Costs – NUG, Dispatchable 1994-2014

	ACF					
	10%		40%		80%	
Plan	**¢/kWh**	**$/kW**	**¢/kWh**	**$/kW**	**¢/kWh**	**$/kW**
15	10.0	1080	4.6	1980	3.4	2920
22	11.6	1240	4.7	2030	3.3	2860
24	9.6	1030	4.6	1960	3.4	2940

Note: ¢/kWh and $/kW are alternative representations of avoided costs, they are not additive.

Figure 16-10a **Avoided Costs Depend on Dispatchablity**
Avioded Costs – NUG, Dispatchable, 1994-2014

	ACF					
	10%		40%		80%	
Plan	**¢/kWh**	**$/kW**	**¢/kWh**	**$/kW**	**¢/kWh**	**$/kW**
15	10.0	1080	4.6	1980	3.4	2920
22	11.6	1240	4.7	2030	3.3	2860
24	9.6	1030	4.6	1960	3.4	2940

Note: ¢/kWh and $/kW are alternative representations of avoided costs, they are not additive.

Figure 16-10b **Avoided Costs Depend on Dispatchablity**
Avoided Costs – NUG, Dispatchable, 1994-2014

	ACF					
	10%		40%		80%	
Plan	**¢/kWh**	**$/kW**	**¢/kWh**	**$/kW**	**¢/kWh**	**$/kW**
15	3.2	340	3.2	1360	3.2	2720
22	3.1	330	3.1	1320	3.1	2650
24	3.2	340	3.2	1370	3.2	2750

Note: ¢/kWh and $/kW are alternative representations of avoided costs, they are not additive.

A second example shows the results if the NUGs are not dispatchable, Figure 16-10.

The dispatchable results assume that output of the NUG can be controlled by the system control centre, and that its use can be arranged to coincide with times of maximum system need. The non-dispatchable results assume that the NUGs energy is produced at random through the year and it has a lower credit for capacity savings, effectively discounting its capacity by its annual load factor.

Such a non-dispatchable NUG has the same avoided cost on an energy basis regardless of capacity factor (3.2 cents/kWh for Plan 15).

The avoided costs for the 20 year period 2004 to 2024, is higher than for the 20 year period 1994 to 2014. For an 80% ACF and Plan 15, the increase is about 15%. The difference would have been larger if a capacity credit had not been given to the NUGs in the short term.

A third NUG example is to show how avoided costs vary with time periods. This is reflected in the results shown in Figure 16–11 which shows the results if the in-service period for the NUGs are 2004 to 2024 instead of 1994 to 2014. Without the capacity credit in the 1990s, the near term values would be lower and the difference due to delaying in-service dates would be larger.

Avoided Cost Examples – Demand Management

The same considerations of energy production, timing and dispatchability, that go into the evaluation of the avoided costs of NUGs, apply to demand management and hydraulic.

Figure 16–12 shows the avoided cost for two demand management options. The options are a thermal envelope upgrade which saves energy only over the winter heating period, and a high efficiency industrial motor program targeted at motors that are running most of the year.

The avoided costs are expressed in cents per kWh of customer load reduction. They are shown for Plan 15, and for the upper, median and lower load forecasts. The costs assume the options are installed in the year 2000.

The thermal envelope upgrade, which is assumed to have a life of 40 years, has an avoided cost of 7.0 cents per kWh in the median growth case. This credits the option with capacity savings and energy savings (at about 36% ACF) mainly during the winter heating season, coincident with Hydro's high avoided cost period.

The industrial high efficiency motor program (80% ACF, 10 year life) has an avoided cost of 4.1 cents per kWh for the median load forecast. This reflects a higher ACF than the thermal envelope upgrade.

Demand Management options are credited for savings in capital and operating costs of transmission and distribution, and the value of reduced losses. The distribution costs savings include those associated with the municipal utilities.

Individual electrical efficiency improvements (EEI) may or may not affect the cost of local distribution. However, a province wide EEI program will have an effect. A credit is applied to demand management options based on their average effect, but this effect is recognized to be different from program to

Figure 16–11a **Avoided Costs Depend on Time Period**
Avoided Costs – NUG, Dispatchable, 1994-2014

	ACF					
	10%		40%		80%	
Plan	**¢/kWh**	**$/kW**	**¢/kWh**	**$/kW**	**¢/kWh**	**$/kW**
15	10.0	1080	4.6	1980	3.4	2920
22	11.6	1240	4.7	2030	3.3	2860
24	9.6	1030	4.6	1960	3.4	2940

Note: ¢/kWh and $/kW are alternative representations of avoided costs, they are not additive

Figure 16–11b **Avoided Costs Depend on Time Period**
Avoided Costs – NUG, Dispatchable, 1994-2014

	ACF					
	10%		40%		80%	
Plan	**¢/kWh**	**$/kW**	**¢/kWh**	**$/kW**	**¢/kWh**	**$/kW**
15	10.7	1190	5.3	2360	3.9	3450
22	14.9	1660	5.6	2470	3.6	3210
24	9.4	1040	5.3	2340	4.0	3550

Note: ¢/kWh and $/kW are alternative representations of avoided costs, they are not additive

Figure 16–12a **Avoided Costs of Demand Management 1989 c/kWh**
Residential Thermal Envelope Upgrade

Load Growth	**Generation & Fuel**	**Transmission**	**Distribution**	**Total**
Upper	5.8	0.8	0.7	7.3
Median	5.5	0.8	0.7	7.0
Lower	4.9	0.8	0.7	6.4

Note Expected avided costs – Proposed Plan

Figure 16–12b **Avoided Costs of Demand Management 1989 ¢/kWh High Efficiency Motors (Industrial)**

Load Growth	Generation & Fuel	Transmission	Distribution	Total
Upper	4.5	0.3	0.0	4.8
Median	3.8	0.3	0.0	4.1
Lower	3.1	0.3	0.0	3.4

Note: Expected avided costs – Proposed Plan

Figure 16–13 **Avoided Costs Hydraulic Niagara Development**

Plan	1989 ¢/kWh	1989 $/kW*
15	5.3	2830
22	5.8	3200
24	5.1	2740

Note: Expected avoided costs.
¢/kWh and $/kW are alternative representations of avoided costs, they are not additive.
** Based on net capacity*

program. For example, the motor program receives no distribution benefits as most industry is connected directly to the transmission or the sub-transmission system.

Avoided Cost Example – Hydraulic

Avoided costs are also used by Hydro to evaluate its hydraulic options.

Figure 16–13 shows the avoided cost calculated for the Niagara development. The Niagara development gets credit for being dispatchable within a day, but not for seasonal dispatchability. It has an intermediate capacity factor and the resulting expected avoided cost, shown in this table, varies from 5.1 to 5.8 cents/kWh depending on the plan chosen.

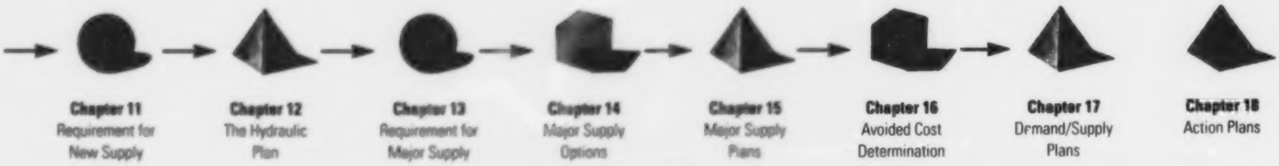
Avoided Cost Feedback

The avoided costs presented in this chapter are based on the candidate plans. The determination of avoided costs and plans is an iterative process.

The avoided costs developed in this chapter were not used to re-evaluate the NUG Plan. These avoided costs are lower than typical purchase rates considered in the development of the NUG plan.

The avoided costs shown in Chapter 12 for the hydraulic options are based on the avoided costs for the Proposed Major Supply Plan shown in this chapter.

The analysis of the attainable induced electrical efficiency improvements was repeated with avoided costs from Plan 15 to check that the result is consistent with the demand management plan. This analysis is presented in Chapter 7. ■


Chapter 11
Requirement for New Supply
Chapter 12
The Hydraulic Plan
Chapter 13
Requirement for Major Supply
Chapter 14
Major Supply Options
Chapter 15
Major Supply Plans
Chapter 16
Avoided Cost Determination
Chapter 17
Demand/Supply Plans
Chapter 18
Action Plans

17 · DEMAND/SUPPLY PLANS

This chapter provides a summary of the components of the three candidate Demand/Supply Plans. Each Demand/Supply Plan includes the Demand Management, Non-Utility Generation, Hydraulic Generation and Rehabilitation Plans along with one of the Major Supply Plans.

As illustrated in Figure 17–1, each Demand/Supply Plan has an associated Action Plan, which is described in Chapter 18.

The description of each plan shows how plan components would be adjusted to accommodate higher and lower load growth. The three Demand/Supply Plans are also sufficiently robust and resilient to accommodate other future uncertainties.

Each of the three candidate Demand/Supply Plans provides an acceptable balance after considering all of the planning factors. One of the three Demand/Supply Plans is identified as the Proposed Demand/Supply Plan – the plan which best meets the future electricity needs of customers to 2014 and beyond. The chapter presents a summary of rationale for the selection of the Proposed Demand/Supply Plan.

Summary of Plan Components

Each of the three Demand/Supply Plans is made up of common components such as demand management and non-utility generation, as well as variable components for major supply. A summary of plan components and their contributions to meeting electricity needs is set out below for the three Demand/Supply plans.

The common components are discussed first:

- Demand Management;
- Non-Utility Generation;
- Rehabilitation;
- Hydraulic Generation; and,
- Manitoba Purchase.

This is followed by a discussion of the Demand/Supply Plans which include the variable components:

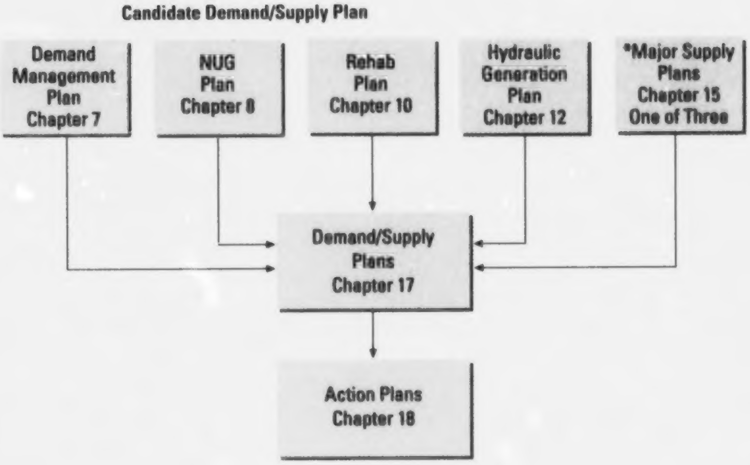
- Fossil Generation; and,
- Nuclear Generation.

Common Components

Each of the three Demand/Supply Plans is designed to attain the maximum economic contribution from the common components. The contributions of the common components are presented below.

Figure 17–1 **Structure of Demand/Supply Plans**

- Proposed Demand/Supply Plan 15
- Alternative Demand/Supply Plan 22 (Higher Nuclear)
- Alternative Demand/Supply Plan 24 (Higher Fossil)


Candidate Demand/Supply Plan
Demand Management Plan Chapter 7
NUG Plan Chapter 8
Rehab Plan Chapter 10
Hydraulic Generation Plan Chapter 12
*Major Supply Plans Chapter 15 One of Three
Demand/Supply Plans Chapter 17
Action Plans Chapter 18

* • Proposed Major Supply Plan 15
- Alternative Major Supply Plan 22 (Higher Nuclear)
- Alternative Major Supply Plan 24 (Higher Fossil)

About 3000 MW of needed capacity will come from hydraulic power.

Demand Management Plan

- Electrical Efficiency Improvements adopted over the planning period (January 89–December 2014) reduce peak power and energy requirements by the amounts shown in Figure 17–2.

Year		Load Forecast	
End	Lower	Median	Upper
2000	1600	2000	2500
2014	2475	3400	4250

Annual Energy Reduction (TWh)

Year		Load Forecast	
End	Lower	Median	Upper
2000	8.0	10.0	12.5
2014	12.4	17.0	21.2

- Load Shifting programs adopted over the planning period reduce peak power requirements by the amounts shown in Figure 17–3. Load shifting does not reduce energy requirements.

Year		Load Forecast	
End	Lower	Median	Upper
2000	800	1000	1200
2014	1080	1280	1480

- Capacity Interruptible Loads reduce peak power requirements by the amounts shown in Figure 17–4. Interruptible loads do not reduce energy requirements.

Year		Load Forecast	
End	Lower	Median	Upper
1988*	763	763	763
2000	599	702	798
2014	771	890	976

*actual

- Total Demand Management demand reduction is shown in Figure 17–5.

Year		Load Forecast	
End	Lower	Median	Upper
1988	763	763	763
2000	2999	3702	4498
2014	4326	5570	6706

*Includes 763 MW of Capacity Interruptible Loads in effect in December 1988

Annual Energy Reduction (TWh)

Year		Load Forecast	
End	Lower	Median	Upper
2000	8.0	10.0	12.5
2014	12.4	17.0	21.2

Non-Utility Generation Plan

- Demand Displacement NUGs reduce peak power and energy requirements on Ontario Hydro's system by the amounts shown in Figure 17–6.

Year		Load Forecast	
End	Lower	Median	Upper
2000	342	403	472
2014	382	456	522

Annual Energy Reduction (TWh)

		Load Forecast	
Year	Lower	Median	Upper
2000	2.7	3.0	3.7
2014	3.0	3.4	4.1

- Purchase NUGs adopted over the planning period increase the supply capacity and energy by the amounts shown in Figure 17–7.

Year		Load Forecast	
End	Lower	Median	Upper
2000	435	932	1133
2014	864	1522	1660

**Net of NUG retirements*

Annual Energy (TWh)

		Load Forecast	
Year	Lower	Median	Upper
2000	3.0	6.4	7.6
2014	5.8	10.3	11.2

- The total Non-Utility Generation contribution over the planning period in terms of net installed capacity and annual energy is shown in Figure 17–8.

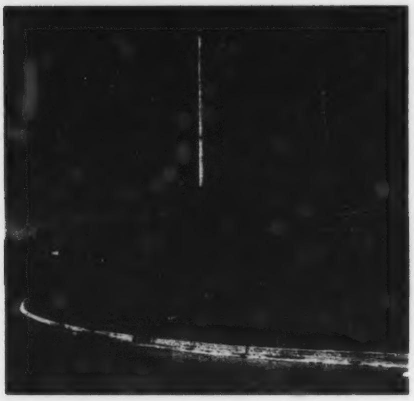
Year		Load Forecast	
End	Lower	Median	Upper
2000	797	1358	1632
2014	1268	2004	2212

Annual Energy (TWh)

Year		Load Forecast	
End	Lower	Median	Upper
2000	5.7	9.4	11.3
2014	8.8	13.7	15.3

Figure 17-9 Manitoba Purchase

Period (Nov 1 - Oct 31)	Capacity (MW)	Annual Energy (TWh)
1998 – 2000	200	1.4
2000 – 2001	400	3.0
2001 – 2002	600	4.7
2002 – 2003	1000	6.8
2003 – 2018	1000	7.0
2018 – 2020	800	5.6
2020 – 2021	600	4.2
2021 – 2022	400	2.8



Victoria Hospital in London produces electricity from waste.

Rehabilitation Plan

- The Rehabilitation Plan involves programs to rehabilitate hydraulic, fossil and nuclear facilities to ensure maximum use is made of existing facilities. The Rehabilitation Plan will include work on more than 20 GW of existing generating facilities over the plan period.
- The main elements of the plan are listed below:

Hydraulic

- Small Hydro Assessment & Retrofit Program;
- Turbine Upgrade Program;
- Process Control Improvement Program;
- Dam Safety Assessment Program.

Fossil

- Acid Gas Reduction;
- Lakeview Rehabilitation;
- Lambton Rehabilitation;
- Other Fossil Station Rehabilitation.

Nuclear

- Fuel Channel Rehabilitation;
- Nuclear Plant Life Assurance;
- Pickering Output Increase.

Hydraulic Plan

The Hydraulic Plan includes redevelopments, extensions or new developments at:

- Lake Gibson;
- Big Chute;
- Kipling;
- Smoky Falls;
- Harmon;
- Little Long;
- Little Jackfish;
- Niagara;
- Abitibi Canyon;
- Otter Rapids;
- Nine Mile Rapids.

In terms of capacity, the Hydraulic Plan provides:

- 1209 MW by the end of year 2000; and
- 2849 MW by the end of year 2014.

In terms of energy the Hydraulic Plan provides:

- 3.0 TWh of energy in the year 2000; and
- 5.8 TWh of energy in the year 2014.

The Hydraulic Plan is the same for the lower, median and upper load forecast.

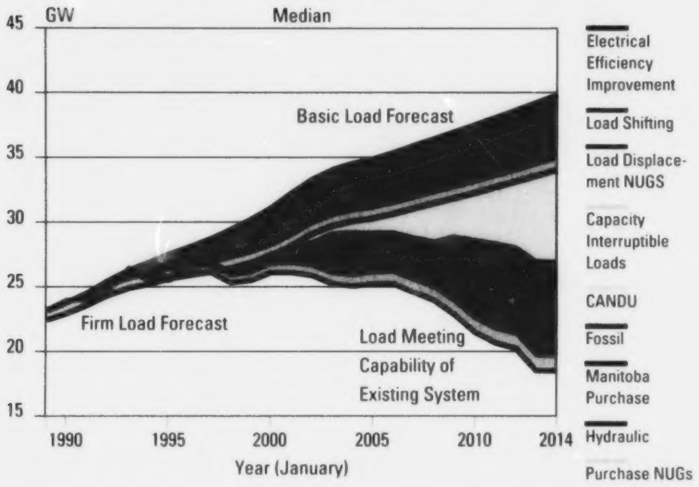
Manitoba Purchase

- All plans include a firm purchase of 1000 MW from Manitoba beginning in 1998. It provides energy and capacity as shown in Figure 17–9.

Variable Components

The variable components of the Demand/Supply Plans are CANDU, Conventional Steam Cycle coal, IGCC, Combined Cycle and gas-fueled Combustion Turbine Units.

Figure 17–10 **Meeting Ontario's Electricity Demand** Plan 15 – Proposed Plan



Candidate Demand/Supply Plan 15

- Demand/Supply Plan 15 includes the Demand Management Plan, Non-Utility Generation Plan, Rehabilitation Plan, Hydraulic Plan and Major Supply Plan 15, including the Manitoba Purchase.
- The variable components of this plan are CANDU stations for base load requirements and Combustion Turbine Units for peaking requirements. Intermediate requirements are met by existing fossil generation.
- Figure 17–10 shows the contribution of each of the plan components to meeting the demand/supply requirements for the median load forecast
- Figure 17-11 shows the same information on the plan components in tabular form at five year intervals.

The top half of the chart shows how the Basic Load Forecast (BLF) is reduced by the firm demand reducing options to the Firm Load Forecast (FLF).

The bottom half shows how the Existing System Load Meeting Capability (ES-LMC) is expanded by the five supply increasing options to the Future System Load Meeting Capability (FS-LMC).

The centre of the table shows the balance between the demand and supply.

- The first unit in-service dates of the CANDU stations (4 X 881 MW) in the plan are as follows:

	Load Forecast		
	Lower	Median	Upper
CANDU A	2009	2003	2002
CANDU B	2012	2009	2007
CANDU C	–	2012	2008
CANDU D	–	–	2012

- The majority of the peaking generation is gas-fueled Combustion Turbine Units with capability to be converted to Combined Cycle and IGCC at a later date (CTU/IGCC).
- Winter Peak Capacity of CTU/IGCC installed (MW) is:

	Load Forecast		
	Lower	Median	Upper
1995	0	0	0
2000	0	0	1344
2005	0	336	2016
2010	1008	3024	2016
2014	2352	4368	2688

- The remainder of the peak load generation is gas-fueled Combustion Turbine Units (CTU/G) some of which will be convertible to Combined Cycle (CTU/CC).
- CTU/G are installed at existing sites in varying amounts dictated by site and transmission capability.
- Winter Peak Capacity of CTU/G installed (MW) is:

	Load Forecast		
	Lower	Median	Upper
1995	0	0	1344
2000	0	0	1344
2005	0	1008	3360
2010	1008	1008	3696
2014	1008	1008	3696

[illegible]

		Jan. 1989	Jan. 1994	Jan. 1999	Jan. 2004	Jan. 2009	Jan. 2014
	Basic Load Forecast (BLF)	23.2	26.9	30.2	34.5	37.0	39.8
Demand	Electrical Efficiency Improvements (EEI)	0.0	0.2	1.4	2.3	2.8	3.3
Reducing	Load Shifting (LS)	0.0	0.6	0.9	1.1	1.2	1.3
Options	Non-Utility Generation – Demand Displacement (NUG-DD)	0.0	0.3	0.4	0.4	0.4	0.5
	Capacity Interruptible Load (CIL)	0.7	0.6	0.7	0.7	0.8	0.9
Balance	Firm Load Forecast (FLF)	22.4	25.2	26.8	30.0	31.8	33.9
	Future System – Load Meeting Capability (FS-LMC)	23.2	25.8	27.1	30.0	31.8	34.2
Supply	Fossil (TH)	0.0	0.0	0.0	1.1	2.4	4.3
Increasing	Nuclear (NU)	0.0	0.0	0.0	0.7	2.8	7.1
Options	Utility Purchase (UP)	0.0	0.0	0.2	0.8	0.8	0.8
	Hydraulic (HY)	0.0	0.02	0.9	1.5	1.8	2.2
	Purchase Non-Utility Generation (P-NUG)	0.0	0.3	0.6	0.9	1.1	1.2
	Existing System – Load Meeting Capability (ES-LMC)	23.2	25.5	25.5	25.0	22.8	18.5
	*Retirements	0.0	0.0	0.0	0.6	2.3	7.0
Meeting	Required Demand/Supply (R-D/S)	0.0	1.4	4.7	9.5	14.1	21.3
Requirements	Demand Reductions in the Plan	0.7	1.7	3.4	4.5	5.2	5.9
	*Supply Increases in the Plan	0.0	0.3	1.7	4.9	9.0	15.7
	Plans Total	0.7	2.0	5.0	9.4	14.1	21.6

Note: All supply options expressed in Load Meeting Capability

Candidate Demand/Supply Plan 22 (Higher Nuclear)

- Demand/Supply Plan 22 includes the Demand Management Plan, Non-Utility Generation Plan, Rehabilitation Plan, Hydraulic Plan and Major Supply Plan 22, including the Manitoba Purchase.
- The variable components of this plan are CANDU stations for base load requirements and part of the intermediate load requirements, and Combustion Turbine Units for peaking requirements. Compared to Demand/Supply Plan 15, the CANDU stations are installed sooner. The remaining intermediate requirements are met by existing fossil generation.
- Figure 17–12 shows the contribution of each of the plan components to meeting the demand/supply requirements for the median load forecast.
- Figure 17–13 shows the same information on the plan components in tabular form at five year intervals.
- The first unit in-service dates of the CANDU stations (4 x 881 MW) in the plan are as follows:

	Load Forecast		
	Lower	Median	Upper
CANDU A	2007	2001	2001
CANDU B	2010	2006	2005
CANDU C	–	2010	2008
CANDU D	–	–	2011

- The majority of the peaking generation is gas-fueled Combustion Turbine Units with capability to be converted to Combined Cycle and IGCC at a later date (CTU/IGCC).
- Winter Peak Capacity of CTU/IGCC installed (MW) is:

	Load Forecast		
	Lower	Median	Upper
January of:			
1995	0	0	0
2000	0	0	1344
2005	0	0	2016
2010	0	336	2016
2014	1680	2688	2688

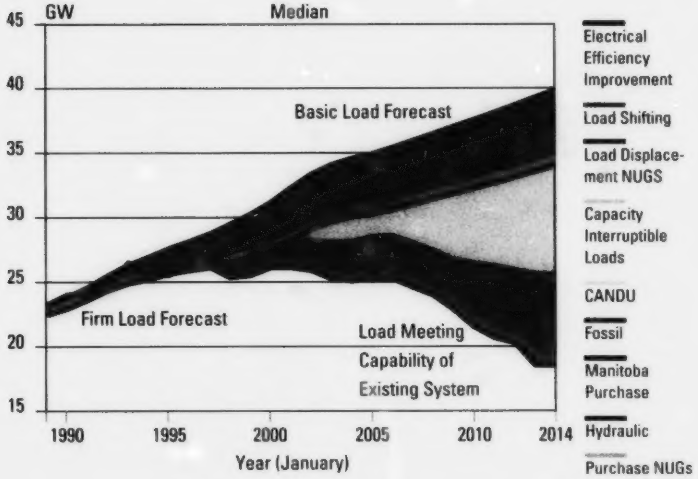
- The remainder of peak load generation is gas-fueled Combustion Turbine Units (CTU/G) some of which will be convertible to Combined Cycle (CTU/CC).
- CTU/G are installed at existing sites in varying amounts dictated by site and transmission capability.
- Winter Peak Capacity of CTU/G installed (MW) is:

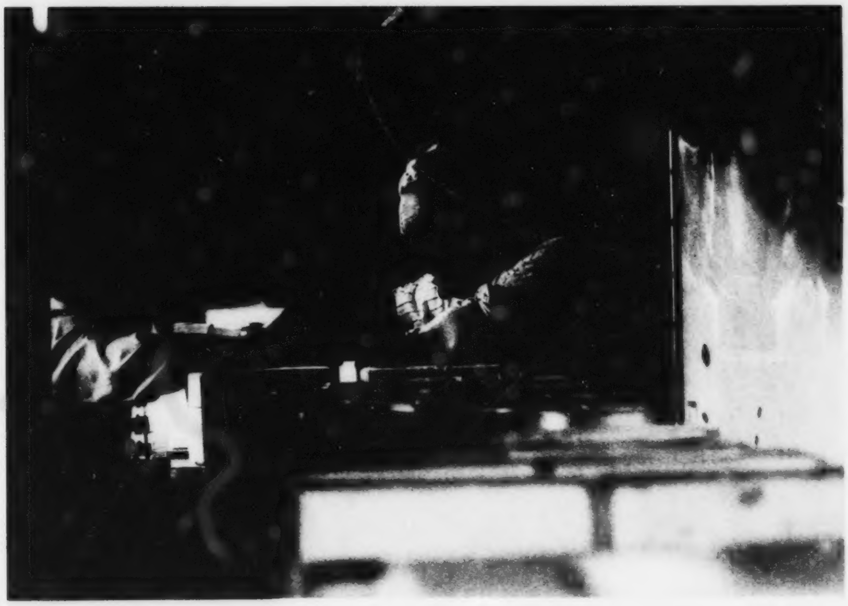
	Load Forecast		
	Lower	Median	Upper
January of:			
1995	0	0	1344
2000	0	0	1344
2005	0	0	2352
2010	0	1008	3024
2014	0	1008	3024

Candidate Alternative Demand/Supply Plan 24 (Higher Fossil)

- Demand/Supply Plan 24 includes the Demand Management Plan, Non-Utility Generation Plan, Rehabilitation Plan, Hydraulic Plan and Major Supply Plan 24, including the Manitoba Purchase.
- The variable components of this plan are a combination of CSC coal and CANDU stations for base load requirements, and Combustion

Figure 17–12 **Meeting Ontario's Electricity Demand** Plan 22 – Higher Nuclear



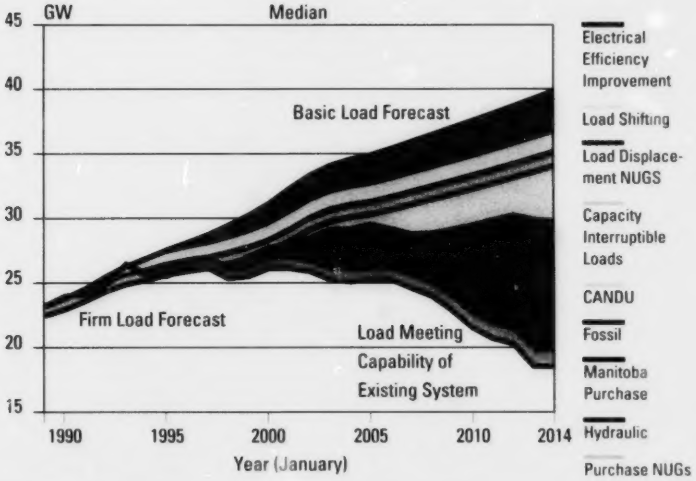


Customers are encouraged to use electricity efficiently through incentives and information programs

		Jan. 1989	Jan. 1994	Jan. 1999	Jan. 2004	Jan. 2009	Jan. 2014
	Basic Load Forecast (BLF)	23.2	26.9	30.2	34.5	37.0	39.8
Demand	Electrical Efficiency Improvements (EEI)	0.0	0.2	1.4	2.3	2.8	3.3
Reducing	Load Shifting (LS)	0.0	0.6	0.9	1.1	1.2	1.3
Options	Non-Utility Generation – Demand Displacement (NUG-DD)	0.0	0.3	0.4	0.4	0.4	0.5
	Capacity Interruptible Load (CIL)	0.7	0.6	0.7	0.7	0.8	0.9
Balance	Firm Load Forecast (FLF)	22.4	25.2	26.8	30.0	31.8	33.9
	Future System – Load Meeting Capability (FS-LMC)	23.2	25.8	27.1	30.3	31.7	34.3
Supply	Fossil (TH)	0.0	0.0	0.0	0.0	0.3	3.0
Increasing	Nuclear (NU)	0.0	0.0	0.0	2.1	5.0	8.5
Options	Utility Purchase (UP)	0.0	0.0	0.2	0.8	0.8	0.8
	Hydraulic (HY)	0.0	0.02	0.9	1.5	1.8	2.2
	Purchase Non-Utility Generation (P-NUG)	0.0	0.3	0.6	0.9	1.1	1.2
	Existing System – Load Meeting Capability (ES-LMC)	23.2	25.5	25.5	25.0	22.8	18.5
	*Retirements	0.0	0.0	0.0	0.6	2.3	7.0
Meeting	Required Demand/Supply (R-D/S)	0.0	1.4	4.7	9.5	14.1	21.3
Requirements	Demand Reductions in the Plan	0.7	1.7	3.4	4.5	5.2	5.9
	*Supply Increases in the Plan	0.0	0.3	1.7	5.3	8.9	15.8
	Plans Total	0.7	2.0	5.0	9.8	14.1	21.7

Note: All supply options expressed in Load Meeting Capability

Figure 17–14 **Meeting Ontario's Electricity Demand** Plan 24 – Higher Fossil



The Demand/Supply Plan includes combustion turbine units which can be converted into IGCC stations like this one in the US.

Turbine Units for peaking requirements. Intermediate requirements are met by existing fossil generation.

- Figure 17–14 shows the contribution of each of the plan components to meeting the demand/supply requirements for the median load forecast.
- Figure 17–15 shows the same information on the plan components in tabular form at five year intervals.
- The first unit in-service dates of the CSC coal station (4 x 800 MW) and the CANDU stations (4 x 881 MW) in the plan are as follows:

	Load Forecast		
	Lower	Median	Upper
CANDU A	2009	2003	2002
CSC A	2012	2009	2007
CANDU B	–	2012	2008
CANDU C	–	–	2012

- The majority of the peaking generation is gas-fueled Cumbustion Turbine Units with capability to be converted to Combined Cycle and IGCC at a later date (CTU/IGCC).
- Winter Peak Capacity of CTU/IGCC installed (MW) is:

	Load Forecast		
	Lower	Median	Upper
January of:			
1995	0	0	0
2000	0	0	1344
2005	0	336	3024
2010	1344	3693	3360
2014	2352	5040	4032

- The remainder of the peak load generation is gas-fueled Combustion Turbine Units (CTU/G) some of which will be convertible to Combined Cycle (CTU/CC).

- CTU/G are installed at existing sites in varying amounts dictated by site and transmission capability.
- Winter Peak Capacity of CTU/G installed (MW) is:

	Load Forecast		
	Lower	Median	Upper
January of:			
1995	0	0	1344
2000	0	0	1344
2005	0	1008	2352
2010	1008	1008	3024
2014	1008	1008	3024

Plans are Robust and Resilient

The Demand/Supply Plans are designed to accomodate many uncertainties without adverse impact on electricity service. In this regard, all three Demand/Supply Plans are robust and resilient. They provide considerable flexibility and are expected to meet a range of reasonable future events while continuing to:

- supply reliable electricity service;
- maintain low customer cost;
- meet current environmental regulatory requirements; and
- achieve high performance with regard to worker and public safety.

All three Demand/Supply Plans contain a mix of fossil and nuclear options which, within reasonable limits, offer flexibility to accommodate the following uncertainties:

- variations in the load growth outside the bandwidth forecast;
- development of new options;
- more stringent environmental and safety requirements;

Nanticoke, Hydro's largest generating station was placed in service in 1973.

[illegible]

		Jan. 1989	Jan. 1994	Jan. 1999	Jan. 2004	Jan. 2009	Jan. 2014
	Basic Load Forecast (BLF)	23.2	26.9	30.2	34.5	37.0	39.8
Demand Reducing Options	Electrical Efficiency Improvements (EEI)	0.0	0.2	1.4	2.3	2.8	3.3
	Load Shifting (LS)	0.0	0.6	0.9	1.1	1.2	1.3
	Non-Utility Generation – Demand Displacement (NUG-DD)	0.0	0.3	0.4	0.4	0.4	0.5
	Capacity Interruptible Load (CIL)	0.7	0.6	0.7	0.7	0.8	0.9
Balance	Firm Load Forecast (FLF)	22.4	25.2	26.8	30.0	31.8	33.9
	Future System – Load Meeting Capability (FS-LMC)	23.2	25.8	27.1	30.0	32.3	34.3
Supply Increasing Options	Fossil (TH)	0.0	0.0	0.0	1.1	3.0	7.3
	Nuclear (NU)	0.0	0.0	0.0	0.7	2.8	4.3
	Utility Purchase (UP)	0.0	0.0	0.2	0.8	0.8	0.8
	Hydraulic (HY)	0.0	0.02	0.9	1.5	1.8	2.2
	Purchase Non-Utility Generation (P-NUG)	0.0	0.3	0.6	0.9	1.1	1.2
	Existing System – Load Meeting Capability (ES-LMC)	23.2	25.5	25.5	25.0	22.8	18.5
	Retirements	0.0	0.0	0.0	0.6	2.3	7.0
Meeting Requirements	Required Demand/Supply (R-D/S)	0.0	1.4	4.7	9.5	14.1	21.3
	Demand Reductions in the Plan	0.7	1.7	3.4	4.5	5.2	5.9
	Supply Increases in the Plan	0.0	0.3	1.7	4.9	9.5	15.8
	Plans Total	0.7	2.0	5.0	9.4	14.7	21.7

Note: All supply options expressed in Load Meeting Capability

The hydraulic plan includes new developments on sites such as the Mattagami River.

Figure 17–16 **Plan at a Glance – Plan 15** Load Meeting Capability

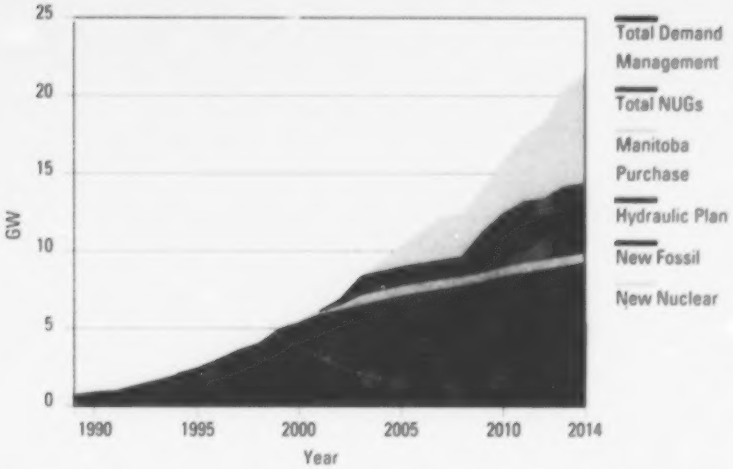
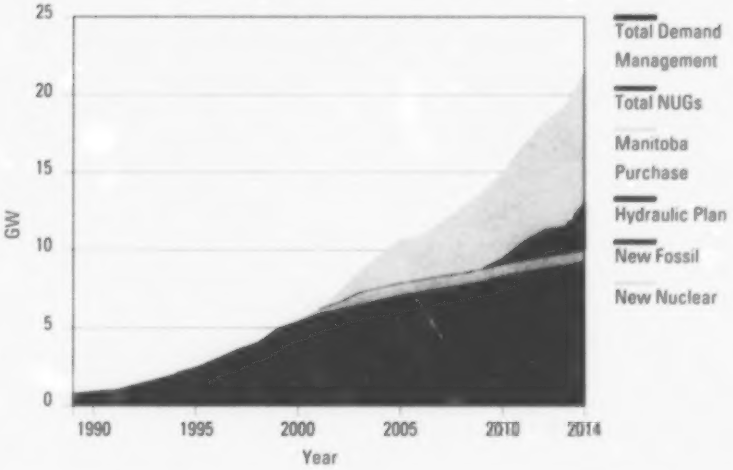


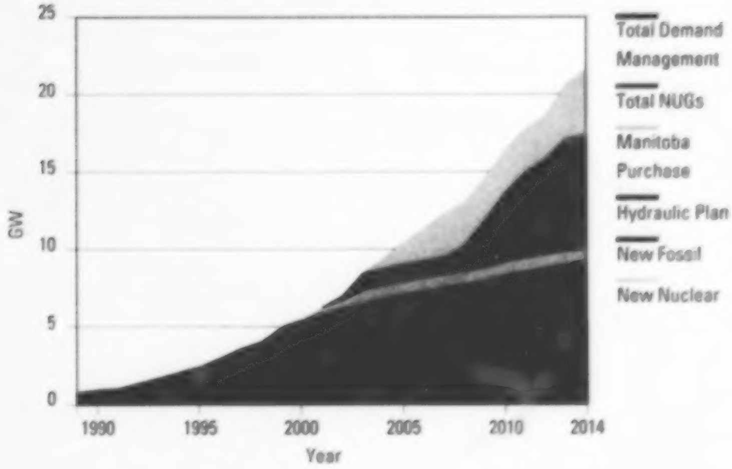
Figure 17–17 **Plan at a Glance – Plan 22** Load Meeting Capability



- variations in fuel prices;
- earlier or later retirement of existing facilities;
- variations in yield of demand management, non-utility generation and hydraulic generation;
- opportunities for purchases from other utilities; and,
- accuracy of nuclear and fossil cost estimates.

For example, if the yield from demand management, non-utility generation or hydraulic generation exceeds expectations, all three Demand/Supply Plans can be adjusted without serious economic consequences by deferring generation commitments. If the yield is less than expected, and there is median growth, all three can be adjusted by implementing some of the options planned for upper growth. However, with upper growth and lower yields, all three plans will require additional options beyond those identified in the Demand/Supply Plans.

Figure 17–18 **Plan at a Glance – Plan 24** Load Meeting Capability



A further example of flexibility relates to uncertainty in fuel prices. The total plan costs are relatively insensitive to fluctuations in prices for coal, uranium and natural gas. Increases in uranium prices have low impact on the cost of base load nuclear generation. Doubling the cost of uranium increases the total cost by about 5%. Changes to coal prices have a much higher impact on the cost of electricity. However, historically, coal prices have been relatively stable and are forecast to remain stable in the future. Gas and oil prices are much higher than coal prices and are much more uncertain in the long term. However, all three Demand/Supply Plans have CTU's which are convertible to combined cycle and IGCC to provide flexibility against gas price increases.

Although many uncertainties are accomodated by the Plans, there is one possible exception. This is the possibility of much stricter acid gas regulations and/or the introduction of greenhouse gas regulations. Demand/Supply Plan 24 (Higher Fossil) has the least flexibility in this regard as it only meets the illustrative CO_2 target for the lower load forecast and has the smallest margin within the current acid gas regulations. Demand/Supply Plan 22 (Higher Nuclear) has the most flexibility to respond to stricter acid gas regulations and the introduction of greenhouse gas regulations.

Overall, Demand/Supply Plan 15 is judged to be the most resilient as it is able to shift towards the Higher Nuclear or the Higher Fossil plans depending upon circumstances.

Plans are Balanced

Each of the three candidate Demand/Supply Plans is balanced with respect to:

- meeting customer needs through demand and supply options;
- responding to customer expectations and values such as reliability, low cost and protection of the environment; and
- having a wide range of new demand and supply options, each of which makes an important contribution to providing customer electricity needs.

Demand/Supply Plan 15 is judged to be the best balanced in terms of the contributions from demand options and supply options and in terms of having the most appropriate mix of generation types.

Figures 17–16, 17–17 and 17–18 show how the various options contribute to each of the candidate plans over the 25 year plan period.

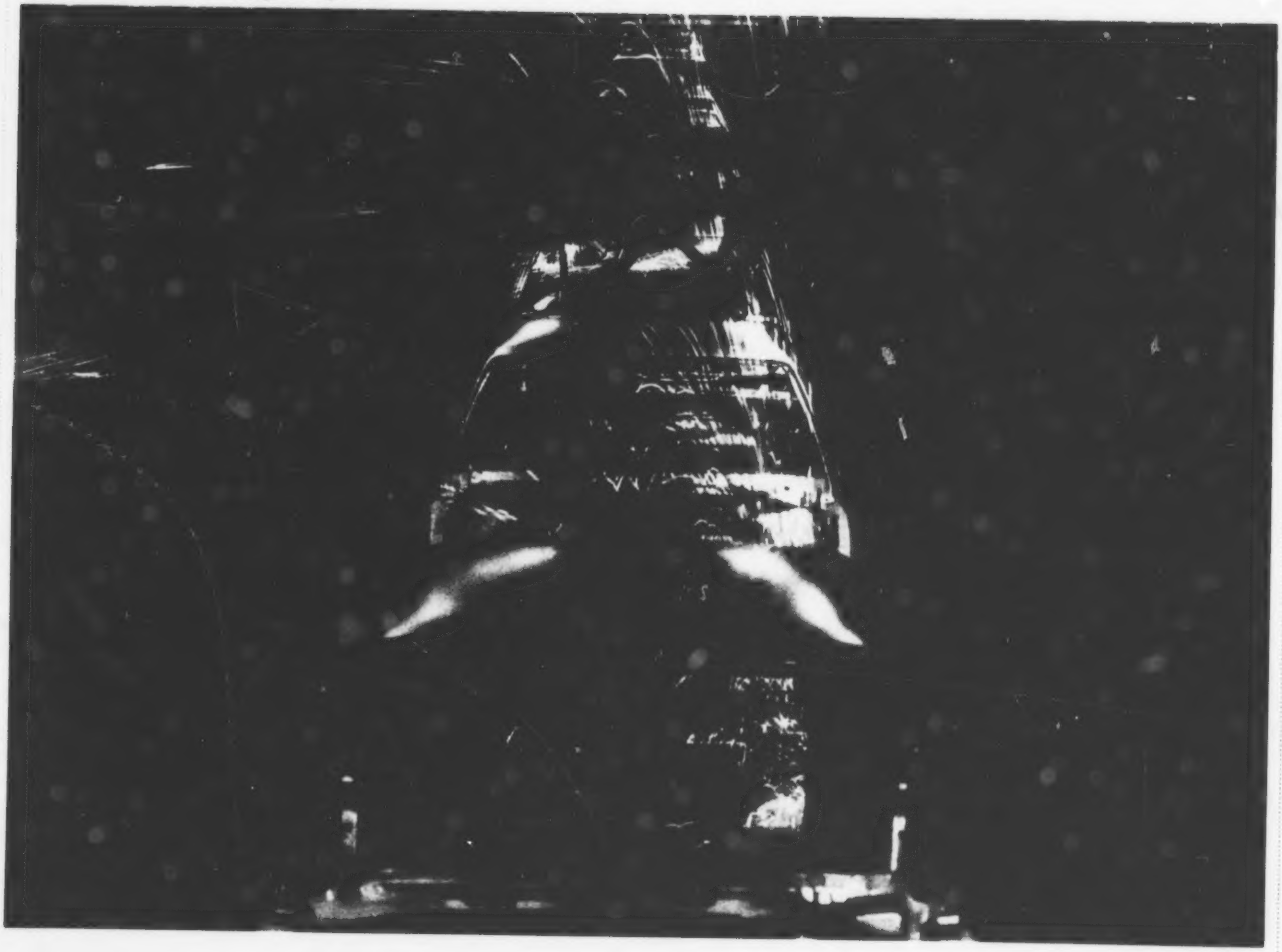
None of the three Demand/Supply Plans is best in all respects. There are major differences among the three plans. Following is a comparison of the three Demand/Supply Plans and the rationale for the selection of Demand/Supply Plan 15 as the proposed plan.

25-year Plan Costs: Plan 15 has the lowest 25-year plan cost. The present value expected cost of Plan 22 is $365 M higher. Plan 24 is $187 M higher (Figure 15–51).

Costs beyond 2014: The long term cost for Plan 15 is much lower. The present value costs of Plan 22 is $938 million higher, and Plan 24 is $712 million higher (Figure 15–55).

Natural uranium is processed and placed in fuel bundles for use in the reactor.

A more energy efficient industrial sector is a key part of Hydro's demand management plan.



Electricity Price and Borrowings: Plan 24 has the lowest electricity prices from 2003 to 2007 and lowest net borrowings from 1997 to 2003 (Figures 15-52, 15-53). In the longer term, electricity prices for Plan 15 will be lower.

Acid Gas Emissions: Plan 22 has the lowest acid gas emissions. Plan 15 has the next lowest. Plan 24 has the highest. Under median load, from 2010 to 2014, annual average emissions for Plan 22 are 90 Gg, Plan 15, 135 Gg, and Plan 24, 150 Gg (Figure 15–30). The flexibility to meet tighter regulations is highest for Plan 22, lowest for Plan 24.

CO_2 Emissions: The illustrative target considered by the Canadian ministers corresponds to 24 teragrams per year for Ontario Hydro by 2005. There is considerable risk that the limits for any actual target that may be adopted could be lower, and the timing earlier, than that considered in the illustrative target. Plan 22 has the lowest CO_2 emissions. It meets the illustrative target for the lower and median load forecast and almost meets it for the upper forecast. Plan 15 meets the target for the lower and median forecasts, and, except from 2005 to 2009, meets the upper forecast. Plan 24 does not meet the illustrative target for the median and upper load forecasts.

Balance of Trade: In the long term (2040) Plan 22 has the most favourable balance of trade, $1 billion (1989 present value) over Plan 15. Plan 24 is the least favourable, about $300 million (1989 present value) less than Plan 15.

Radioactivity Concerns: One dimension of social acceptance is an ongoing public concern with respect to reactor safety and radioactive waste disposal. Plan 22 has the most new nuclear stations, Plan 24 has the least.

Diversity: There are no major changes in diversity between the existing system and the system with any of the three Demand/Supply Plans.

Resource Smoothing: Under median and upper load, Plans 15, 22 and 24 acceptably maintain the capability to design, manufacture, construct and operate nuclear and fossil generation. Under the lower load forecast, there is a significant interruption in the nuclear program, which would adversely affect maintaining the CANDU option.

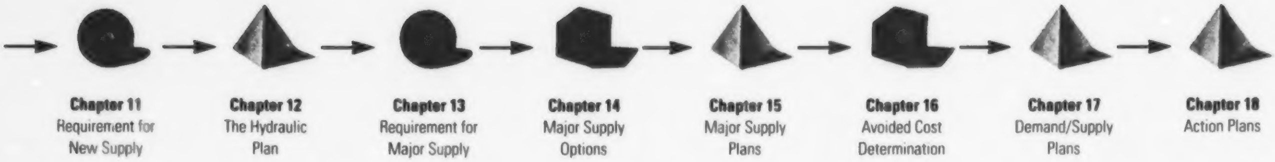
Approval Delays: Plan 24 is less vulnerable to the impact of approval delays than the other Demand/Supply Plans because it has both nuclear and fossil in the preparatory stages – if one is delayed, the other can fill the need.

Proposed Demand/Supply Plan

Demand/Supply Plan 15 is selected as the Proposed Demand/Supply Plan as it achieves balance in both a quantitative and qualitative sense. The Proposed Plan integrates both demand and supply options which meet the forecasts of future customer needs for electricity, while providing reliable, low cost power in an environmentally acceptable manner.

Demand/Supply Plan 15 is also the most robust and resilient of the three candidate plans as it is best able to accommodate uncertainties without adverse impacts on electricity service.

Demand/Supply Plan 15 is proposed to provide the balance of power over the next 25 years.



18. Action Plans

An Action Plan is a set of timely actions which must be taken to implement a Candidate Demand/Supply Plan to meet effectively the future electricity needs of Ontario.

This chapter describes how an Action Plan is developed, and presents the detailed Action Plans corresponding to the Proposed Demand/Supply Plan 15, Alternative Demand/Supply Plan 22 (Higher Nuclear) and Alternative Demand/Supply Plan 24 (Higher Fossil).

How the Action Plan is Developed

The planned in-service date of a generating unit is the date the unit is planned to begin reliably generating electricity. The period prior to the in-service date is called the lead time.† Lead time is divided into two parts – the definition lead time and the acquisition lead time – as shown in Figure 18–1.

Definition lead time is the time required for the development of planning specifications; estimating the costs of the project; pre-engineering; preparation, submission and review of an Environmental Assessment document; and obtaining all the approvals to permit project commitment. Acquisition lead time runs from project commitment to the in-service date of the first unit, and includes detailed design, construction and commissioning activities.

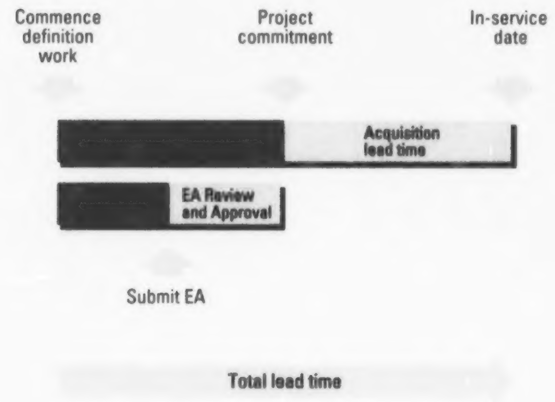
The percentage of capital costs expended during the definition phase† is low (typically 3% to 7%) but the percentage expended during acquisition is high. Accordingly, it is desirable to shorten the acquisition phase,† thereby reducing interest costs during construction. A short acquisition time has the further advantage of reducing uncertainty at the time of project commitment as to what the load will be at the in-service date. This permits "just-in-time" commitment to minimize cost while still reliably meeting the load.

However, if the reliability of electricity supply is to be maintained, the planned acquisition time must also be realistic.

The lead times for the major supply options are set out in Figure 15–6 in Chapter 15. These lead times are expressed as a range, to reflect project specific factors such as siting status (existing or new) and approval requirements. A specific lead time is chosen for each option. Deducting this lead time from the in-service date identifies the date at which the definition phase must start. Deducting the acquisition lead time from the in-service date identifies the project commitment date. Similarly, the date for submitting the Environmental Assessment document is obtained by deducting the time for EA review and approval from the project commitment date.

As stated in the Demand/Supply Planning Strategy (Element 2.2.4), the preparations for the options (definition phase) will be

Figure 18–1 **Supply Options – Load Times**


Commence definition work
Project commitment
In-service date
Acquisition lead time
EA Review and Approval
Submit EA
Total lead time

taken in time to meet the upper load projection, while avoiding the costs of premature commitments.

The Action Plan includes the facilities for which an Environmental Assessment document is expected to be submitted before December 31, 1996, based on meeting the upper load forecast. If the actual load trend is below the upper forecast, the project commitments will be delayed to the "just-in-time" requirement.

Action Plans

The Action Plans for the Proposed Demand/Supply Plan and the two Alternative Demand/Supply Plans are set out in Figures 18–2, 18–3, and 18–4. The high priority plans – Demand Management, Non-Utility Generation and Rehabilitation are shown as ongoing for the entire planning period. The Action Plans associated with the high priority Hydraulic Plan and the Major Supply Plans are also shown on these Figures.

[illegible]

Option	Action	Timing
Demand Management Plan	Implement with High Priority	On going
NUG Plan	Implement with High Priority	On going
Rehabilitation Plan	Implement with High Priority	On going

Option	Capacity MW	Commence Definition Phase	Submit EA	Project Commitment Load Forecast Lower	Median	Upper	First Unit in Service Date Lower	Median	Upper
Manitoba Purchase	1000	–	–		–		1998	1998	1998
(Independent of Load Growth)									
Associated Transmission	1500	Underway	1991	1993	1993	1993	1999	1999	1999
Hydraulic Plan									
(Independent of Load Forecast)									
Little Jackfish	132	Underway	Underway	1992	1992	1992	1996	1996	1996
Lake Gibson	5	Underway	1990	1990	1990	1990	1992	1992	1992
Big Chute	10	Underway	1990	1991	1991	1991	1993	1993	1993
Kipling	68	Underway	1990	1992	1992	1992	1994	1994	1994
Smoky Falls	182	Underway	1990	1992	1992	1992	1995	1995	1995
Harmon	68	Underway	1990	1992	1992	1992	1995	1995	1995
Little Long	61	Underway	1990	1992	1992	1992	1996	1996	1996
Niagara	550	Underway	1991	1993	1993	1993	1998	1998	1998
Canyon/Otter/Nine Mile	932	1991	1994	1996	1996	1996	2000	2000	2000
Demothballing									
R.L. Hearn GS	800	–	–	–		*1992	–	–	1993
Major Supply Plan									
CTU/NC A	672	Underway	1990	–	–	1991	–	–	1993
CTU/NC B	672	Underway	1991	–	–	1992	–	–	1994
CANDU A	3524	1990	1991	2001	1995	1993	2009	2003	2002
CTU/IGCC A	2016	1990	1992	2006	1999	1994	2009	2002	1997
CTU/CC A	1008	1994	1996	2005	1998	1998	2008	2001	2001
CANDU B	3524	1994	1996	2004	2001	1999	2012	2009	2007

** Commence demothballing*

[illegible]

Option	Action	Timing
Demand Management Plan	Implement with High Priority	On going
NUG Plan	Implement with High Priority	On going
Rehabilitation Plan	Implement with High Priority	On going

Option	Capacity MW	Commence Definition Phase	Submit EA	Project Commitment Load Forecast Lower	Median	Upper	First Unit in Service Date Lower	Median	Upper
Manitoba Purchase	1000	–	–		–		1998	1998	1998
(Independent of Load Growth)									
Associated Transmission	1500	Underway	1991	1993	1993	1993	1999	1999	1999
Hydraulic Plan									
(Independent of Load Forecast)									
Little Jackfish	132	Underway	Underway	1992	1992	1992	1996	1996	1996
Lake Gibson	5	Underway	1990	1990	1990	1990	1992	1992	1992
Big Chute	10	Underway	1990	1991	1991	1991	1993	1993	1993
Kipling	68	Underway	1990	1992	1992	1992	1994	1994	1994
Smoky Falls	182	Underway	1990	1992	1992	1992	1995	1995	1995
Harmon	68	Underway	1990	1992	1992	1992	1995	1995	1995
Little Long	61	Underway	1990	1992	1992	1992	1996	1996	1996
Niagara	550	Underway	1991	1993	1993	1993	1998	1998	1998
Canyon/Otter/Nine Mile	932	1991	1994	1996	1996	1996	2000	2000	2000
Demothballing									
R.L. Hearn GS	800	–	–	–		*1992	–	–	1993
Major Supply Plan									
CTU/NC A	672	Underway	1990	–	–	1991	–	–	1993
CTU/NC B	672	Underway	1991	–	–	1992	–	–	1994
CANDU A	3524	1990	1991	1999	1993	1993	2007	2001	2001
CTU/IGCC A	2016	1990	1992	2009	2006	1994	2012	2009	1997
CANDU B	3524	1992	1994	2002	1998	1997	2010	2006	2005

* *Commence demothballing*

Figure 18-4 Action Plan
Alternative Demand/Supply Plan 24 (Upper Forecast)

Option	Action	Timing
Demand Management Plan	Implement with High Priority	On going
NUG Plan	Implement with High Priority	On going
Rehabilitation Plan	Implement with High Priority	On going

Option	Capacity MW	Commence Definition Phase	Submit EA	Project Commitment Load Forecast Lower	Median	Upper	First Unit in Service Date Lower	Median	Upper
Manitoba Purchase	1000	–	–		–		1998	1998	1998
(Independent of Load Growth)									
Associated Transmission	1500	Underway	1991	1993	1993	1993	1999	1999	1999
Hydraulic Plan									
(Independent of Load Forecast)									
Little Jackfish	132	Underway	Underway	1992	1992	1992	1996	1996	1996
Lake Gibson	5	Underway	1990	1990	1990	1990	1992	1992	1992
Big Chute	10	Underway	1990	1991	1991	1991	1993	1993	1993
Kipling	68	Underway	1990	1992	1992	1992	1994	1994	1994
Smoky Falls	182	Underway	1990	1992	1992	1992	1995	1995	1995
Harmon	68	Underway	1990	1992	1992	1992	1995	1995	1995
Little Long	61	Underway	1990	1992	1992	1992	1996	1996	1996
Niagara	550	Underway	1991	1993	1993	1993	1998	1998	1998
Canyon/Otter/Nine Mile	932	1991	1994	1996	1996	1996	2000	2000	2000
Demothballing									
R.L. Hearn GS	800	–	–	–		*1992	–	–	1993
Major Supply Plan									
CTU/NC A	672	Underway	1990	–	–	1991	–	–	1993
CTU/NC B	672	Underway	1991	–	–	1992	–	–	1994
CANDU A	3524	1990	1991	2001	1995	1993	2009	2003	2002
CTU/IGCC A	2016	1990	1992	2006	1999	1994	2009	2002	1997
CTU/IGCC B	1008	1994	1996	2009	2005	1998	2012	2008	2001
CSC A	2966	1994	1996	2005	2002	2000	2012	2009	2007

* *Commence demothballing*

19 APPROVALS

Ontario Hydro has a statutory responsibility to meet electricity needs in Ontario. The three Candidate Demand/Supply Plans are designed to meet these electricity needs in accordance with approved planning criteria.

Chapter 18 identifies Action Plans associated with the three Candidate Plans. Each Action Plan includes a specific Program addressing the requirement and rationale for new electricity supply facilities.

A flexible Program is required by Ontario Hydro because of the uncertainties associated with the various components of the Demand/Supply Plan. For example, if the load is higher than the median forecast, action must be taken now to maintain reliable supply. Similarly if the load is lower than the median forecast or contributions from demand management and non-utility generation are higher than forecast, commitment to the construction of major supply facilities can be delayed.

General Purpose

The General Purpose of the Program is to ensure that a continuing reliable electricity supply is provided in Ontario in a manner consistent with the Demand/Supply Planning Strategy approved by Ontario Hydro's Board of Directors in March, 1989.

Specific Purposes

The Specific Purposes associated with the Program are:

- to obtain approval of the requirement and rationale for transmission facilities to incorporate electricity purchased outside Ontario;
- to obtain approval of the requirement and rationale for the installation in Ontario of specific generation facilities in specific amounts – together with incorporating radial transmission – on a timetable relating to the electricity demand required to be served by Ontario Hydro;
- to address the overall approvals process for generation and radial transmission in a logical, comprehensive and consistent way; and
- to obtain approvals which will avoid duplication of the consideration of planning issues in subsequent project applications.

The Undertaking

The Undertaking, as described in this environmental assessment document, is made up of specific Demand/Supply Plan components, and constitutes a Program in respect of activities associated with meeting future electricity requirements.

The Program submitted for approval represents only a part of the results of the integrated planning which led to the identification of Candidate Demand/Supply Plans. The Plan components not included in the Program either do not require approval, or are not being submitted for approval in this application.

Approval Requested – Program Associated with Proposed Demand/Supply Plan 15

In specific terms, Ontario Hydro is recommending that approval be granted for the following:

1. The requirement and rationale for the transmission facilities to incorporate electricity purchased from Manitoba.

2. The requirement and rationale for the installation in Ontario of the following generating facilities associated with Plan 15 – the Proposed Plan:

Facilities	**Planned Capacity (MW)**
Hydraulic Program	
Lake Gibson	5
Big Chute	10
Kipling	68
Smoky Falls	182
Harmon	68
Little Long	61
Little Jackfish	132
Niagara	550
Abitibi Canyon	463
Otter Rapids	174
Nine Mile Rapids	295
Fossil Program	
CTU/CC – A	
Phase 1 – Gas/Oil – CTU	1008
Phase 2 – Gas/Oil – Combined Cycle (Includes Phase 1)	1442
CTU/IGCC – A	
Phase 1 – Gas/Oil – CTU	2016
Phase 2 – Gas/Oil – Combined Cycle (Includes Phase 1)	2882
Phase 3 – Coal – Integrated Gasification Combined Cycle (Includes Phases 1 and 2)	2824
Nuclear Program	
CANDU A	3524
CANDU B	3524

To avoid duplication, co-ordination will be required between this application and the project approvals for individual hydraulic projects.

3. The requirement and rationale for combustion turbines, not intended for conversion to Combined Cycle or IGCC operation, on existing sites, to be committed as short lead time generating capacity if required to meet electricity demand.

CTU/NC – A	672
CTU/NC – B	672

4. The requirement and rationale for any radial transmission needed to connect the generation facilities listed above into Ontario Hydro's transmission system.

Program Associated with Alternative Demand/Supply Plan 22

One alternative method of carrying out the undertaking is the Program associated with Candidate Plan 22. In specific terms, this Alternative Program includes:

1. The requirement and rationale for the transmission facilities to incorporate electricity purchased from Manitoba.

2. The requirement and rationale for the installation in Ontario of the following generating facilities associated with this alternative method of carrying out the undertaking:

Facilities	**Planned Capacity (MW)**
Hydraulic Program	
Lake Gibson	5
Big Chute	10
Kipling	68
Smoky Falls	182
Harmon	68
Little Long	61
Little Jackfish	132
Niagara	550
Abitibi Canyon	463
Otter Rapids	174
Nine Mile Rapids	295
Fossil Program	
CTU/IGCC – A	
Phase 1 – Gas/Oil – CTU	2016
Phase 2 – Gas/Oil – Combined Cycle (Includes Phase 1)	2882
Phase 3 – Coal – Integrated Gasification Combined Cycle (Includes Phases 1 and 2)	2824
Nuclear Program	
CANDU A	3524
CANDU B	3524

To avoid duplication, co-ordination will be required between this application and the project approvals for individual hydraulic projects.

3. The requirement and rationale for combustion turbines, not intended for conversion to Combined Cycle or IGCC operation, on existing sites, to be committed as short lead time generating capacity if required to meet electricity demand.

CTU/NC – A	672
CTU/NC – B	672

4. The requirement and rationale for any radial transmission needed to connect the generation facilities listed above into Ontario Hydro's transmission system.

Program Associated with Alternative Demand/Supply Plan 24

Another alternative method of carrying out the undertaking is the Program associated with Candidate Plan 24. In specific terms, this Alternative Program includes:

1. The requirement and rationale for the transmission facilities to incorporate electricity purchased from Manitoba.

2. The requirement and rationale for the installation in Ontario of the following generating facilities associated with this alternative method of carrying out the undertaking:

Facilities	Planned Capacity (MW)
Hydraulic Program	
Lake Gibson	5
Big Chute	10
Kipling	68
Smoky Falls	182
Harmon	68
Little Long	61
Little Jackfish	132
Niagara	550
Abitibi Canyon	463
Otter Rapids	174
Nine Mile Rapids	295
Fossil Program	
CTU/IGCC – A	
Phase 1 – Gas/Oil – CTU	2016
Phase 2 – Gas/Oil – Combined Cycle (Includes Phase 1)	2882
Phase 3 – Coal – Integrated Gasification Combined Cycle (Includes Phases 1 and 2)	2824
CTU/IGCC – B	
Phase 1 – Gas/Oil – CTU	1008
Phase 2 – Gas/Oil – Combined Cycle (Includes Phase 1)	1441
Phase 3 – Coal – Integrated Gasification Combined Cycle (Includes Phases 1 and 2)	1412
Conventional Steam Cycle (CSC-Coal)–A	2964
Nuclear Program	
CANDU A	3524

To avoid duplication, co-ordination will be required between this application and the project approvals for individual hydraulic projects.

3. The requirement and rationale for combustion turbines, not intended for conversion to Combined Cycle or IGCC operation, on existing sites, to be committed as short lead time generating capacity if required to meet electricity demand.

CTU/NC – A	672
CTU/NC – B	672

4. The requirement and rationale for any radial transmission needed to connect the generation facilities listed above into Ontario Hydro's transmission system.

Project Approval Process

In keeping with the Purposes of the Program, Ontario Hydro has initiated work on the studies required to support the necessary applications for approvals to locate, on specific sites and rights-of-way, the facilities associated with the approvals requested in this application. In order to prepare and file project specific assessments in a timely way, field studies relating to the identification, evaluation and selection of sites and rights-of-way are now underway. Locations to be considered for the various fossil and nuclear projects will include at least the following:

For CTU/NC

Non-convertible gas/oil fueled CTUs

- Hearn
- Keith
- Lakeview
- Lambton
- Lennox A
- Nanticoke

For CTU/CC

Gas/oil fueled CTUs capable of conversion to Combined Cycle

- Hearn
- Keith

For CTU/IGCC

Gas/oil fueled CTUs capable of conversion to Combined Cycle and further conversion to coal fueled Integrated Gasification Combined Cycle operation

- Lennox B
- Wesleyville
- North Channel Area
- Keith Redevelopment
- Lakeview Redevelopment
- Lambton Redevelopment

For Conventional Steam Cycle – Coal

- Lennox B
- Wesleyville
- North Channel Area
- Lakeview Redevelopment
- Lambton Redevelopment

For CANDU

- Darlington B
- Bruce C
- Wesleyville
- North Channel Area

The project assessments will focus on ensuring that the components included in the approved Program are located and implemented in an environmentally acceptable manner. The project assessments will not duplicate nor reconsider the planning issues determined by this application.

[redacted]

APPENDIX A

Demand/Supply Planning Strategy

(March 1989)

EXTRACT FROM REPORT 666D SP
2.0 PRIORITY STRATEGIC DIRECTIONS

The Demand/Supply Planning Strategy contains five basic Thrusts:

1. Ontario Hydro will give a high priority to the maintenance, upgrading and refurbishment of the existing generation and transmission facilities such as to improve their performance, efficiency and reliability consistent with high standards of environmental protection.

2. Ontario Hydro will give top priority to demand management to reduce load growth through electricity use efficiency and load shifting. Demand management options that contribute to low customer cost of electrical service will be aggressively pursued. The co-operation of municipal utilities, customers, governments and the electrical industry will be essential for the successful delivery of demand management programs.

3. Ontario Hydro will give a high priority to encouraging non-utility generation to provide a part of the need for new resources. Preference will be given to renewable resources such as small hydro and wood waste. Also fossil generation which employs high efficiency cogeneration will be preferred over conventional technology.

4. Ontario Hydro will give a high priority to the orderly development of the remaining economic hydro-electric potential recognizing that this is a renewable but limited resource.

5. Ontario Hydro will keep open the options for major new supply facilities to meet growth and the need to replace old plants and thus ensure a reliable electricity service into the next century. The major supply options are CANDU nuclear, fossil and firm purchases from Manitoba and Quebec.

The Demand/Supply Planning Strategy best meets the future electricity needs of Ontario and will give the flexibility to cope with an uncertain future.

Priority Strategic Directions

- Maintain and improve the existing and committed facilities
- Aggressively pursue economic demand management options
- Encourage non-utility generation
- Undertake the orderly development of the remaining hydro-electric potential
- Keep the major supply options open

THE FULL STRATEGY

4.0 The Demand/Supply Planning Strategy

Each annual Demand/Supply Plan will be developed based on the following strategic considerations:

1.0 General Strategic Principles

1.1 The primary objective of demand/supply programs is to contribute to customer satisfaction.

1.2 Reliability is paramount.

1.3 Low customer cost of electricity service is vital.

1.4 Ontario Hydro will take a leadership role in protecting the environment. Ontario Hydro will encourage the social benefits associated with its activities.

1.5 Rates must continue to be based on costs.

1.6 Flexibility will be provided to accommodate uncertainty and thereby assure future electricity service.

1.7 The primary criteria (which must be met) for evaluating and developing recommended plans are:
- customer satisfaction
- reliability standards
- safety requirements and standards
- environmental requirements and standards
- low costs of electricity service
- social acceptance
- technical soundness
- flexibility

1.8 Secondary criteria will be considered which may influence the recommended plans. Secondary criteria include:
- resource preferences
- diversity
- resource smoothing
- environmental characteristics
- public safety characteristics
- economic impact
- other social considerations

In developing plans, the secondary criteria will be quantified to the degree practical.

2.0 General Demand/Supply Strategies

2.1 *Measures of Cost*

2.1.1 Ontario Hydro will aim to develop a mix of demand and supply options that provides electricity service to customers at low total customer cost.

2.1.2 The cost of meeting social and environmental requirements will be included in cost evaluations of demand/supply options.

2.2 *Response to Uncertain Growth*

2.2.1 The load forecast will include upper and lower projections that cover a reasonable range of possible outcomes together with the probability of these outcomes.

2.2.2 Plans must have flexibility to meet the full range of loads between the upper and lower projections at least risk cost.

2.2.3 Demand options will be implemented, and supply options will be committed, in time to meet the median load growth economically and reliably.

2.2.4 Preparations for demand and supply options will be undertaken in time to meet the upper load projection while avoiding the cost of premature commitment.

2.3 *Resource Smoothing*

2.3 To maintain flexibility and to reduce costs resource smoothing will be considered.

2.4 *Resource Preferences*

2.4.1 Resources meeting the primary criteria will be preferred based on the nature of the primary energy source in the following order:

- electricity use efficiency, renewable energy and waste fuels;
- plentiful fuels;
- scarce fuels,

and based on their source in the following order:

- Ontario indigenous resources and electricity efficiency;
- other Canadian resources;
- foreign resources.

Processes which convert fuel into electrical energy at high efficiency will be favoured.

2.4.2 In choosing the mix of demand and supply options to be developed, capacity diversity and energy diversity will be considered.

2.5 *Public Consultation*

2.5 Consultation with customers, the public, governments and the legislature will continue to be an integral part of the planning process.

3.0 Demand Management

3.1 *Increased Electrical Efficiency*

3.1 Demand reducing options through increased electrical efficiency will be aggressively pursued to the full extent they are economic compared to the available supply options in the relevant planning period.

3.2 *Load Shifting*

3.2.1 Peak power demand reduction through shifting demand from peak to off-peak will be pursued to the full extent it is economic and respects system limits.

3.2.2 The choice between load shifting and energy storage will reflect the costs and benefits of each option.

3.3 *Electrotechnology Transfer*

3.3 Demand programs aimed at improving the Ontario economy or environment will be pursued through electrotechnology development and transfer to Ontario industry. These programs must provide net benefits to the Ontario community and may increase electricity demand.

3.4 *Cooperation with Municipal Utilities and Governments*

3.4.1 The planning and implementation of demand management options will be undertaken in close cooperation with the municipal utilities.

3.4.2 Information on demand management programs will be exchanged with the Federal and Provincial Governments.

3.5 *Timing of Demand Management*

3.5.1 Development and implementation of economic demand reduction programs should be started early enough to be effective in contributing to the most cost effective demand supply balance.

3.5.2 Priority should be given to influencing the new market rather than the retrofit.

3.6 *Demand Management – Research and Development*

3.6.1 Technical research and market development to support existing and planned demand management programs will be given a high priority so that demand options can be efficiently implemented in a timely manner.

3.6.2 To provide flexibility, technical research and market demonstration programs shall be undertaken to provide information on the potential for new demand management programs.

3.7 *Demand Management – Promotion & Education*

3.7 Education, information dissemination, audits, and advertising will be vigorously pursued to make customers, contractors, developers, suppliers, energy service companies, and others aware of the opportunities for the efficient and effective use of electricity.

3.8 *Demand Management – Training*

3.8 Ontario Hydro will cooperate with Municipal Utilities, the Ministry of Energy and other industry participants in training staff in demand management techniques to ensure the timely and effective implementation of demand management programs.

3.9 *Diverse Demand Management Programs*

3.9 To provide opportunity for broad customer participation, Ontario Hydro will offer a diverse set of demand management programs covering all customer sectors and many end uses.

3.10 *Rate Induced Demand Management*

3.10.1 General rates will be based on average costs.

3.10.2 Rates may be time differentiated to give incentives to shift load to off-peak periods.

3.10.3 Special rates for nonstandard conditions of service may be implemented to manage demand for specific purposes.

3.10.4 Special rates should recover at least the additional cost of supplying the electricity sold under these rates.

3.11 *Financial Incentives for Demand Management*

3.11.1 Incentives should be high enough to encourage the development of a large part of the potential that is beneficial to customers in total.

3.11.2 Customers who participate and receive direct benefits should provide a substantial contribution to the cost.

3.11.3 The level of incentives should be acceptable to customers in general.

3.11.4 Financial incentives should be based on lifetime benefits; loans and grants may be used to increase the return to customers in early years.

3.12 *Energy Efficiency Standards*

3.12 Ontario Hydro will work with governments, industry and customers towards developing standards for buildings, appliances, etc., including the highest electrical energy efficiencies that are widely acceptable.

3.13 *Other Barriers*

3.13 Ontario Hydro will identify other barriers to increased efficiency and work with other parties as appropriate towards the reduction or elimination of such barriers.

3.14 *Demand Management-Monitoring and Post-Audit*

3.14 Ontario Hydro will put into place a monitoring and post-audit system to effectively estimate the incentive driven demand reduction being achieved.

4.0 Non-Utility Generation

4.1 *Rates and Incentives*

4.1.1 Rates for purchasing electricity from non-utility generators and incentives for non-utility generation projects shall be up to the avoided cost to the system as a whole.

4.1.2 Rates and incentives for non-utility generation may vary because avoided cost depends on many factors, including the reliability, timing and location of the deliveries.

4.1.3 Ontario Hydro will regularly communicate the need for non-utility generation to potential non-utility generators; request proposals to contribute to that need; and negotiate detailed terms and conditions with suppliers whose proposals have potential to satisfactorily meet the need.

4.1.4 Ontario Hydro will establish standard rates for purchases of non-utility generation having a capacity of five megawatts or less. The standard rates for hydroelectric or other renewable sources will be set at full avoided cost.

4.2 *Co-operation with Government and Industry*

4.2.1 Ontario Hydro will cooperate with governments, the non-utility generation industry, and other interested parties to ensure effective and timely development of economic non-utility generation.

4.2.2 Ontario Hydro will cooperate with the non-utility generation industry and the appropriate regulatory authorities to facilitate timely approval of environmentally responsible non-utility generation.

4.2.3 Ontario Hydro will cooperate with the Ministry of Natural Resources in respect to the release and development of hydroelectric sites. Where Ontario Hydro is not interested in developing a particular site, Ontario Hydro will promptly advise the Ministry of Natural Resources so that such sites can be released to other interested parties.

5.0 Ontario Hydro – Supply

5.1 *Supply General*

5.1.1 Major increases in supply will be provided by low cost options available to meet the need after allowing for the effects of demand management and non-utility generation. A broad range of options will be considered, including hydraulic, CANDU nuclear, coal, natural gas, oil and purchases from neighbouring utilities.

5.1.2 Evaluations of supply options will consider the long term availability and price for fuels.

5.2 *Approvals*

5.2.1 Ontario Hydro will seek improvements to the planning approval process to provide increased flexibility.

5.2.2 Approval for new transmission to incorporate new generation shall be sought as part of the generation approval process.

5.3 *Unit Sizes, Plant Size and Flexibility*

5.3 Single or two unit commitment of economically sized units in multi-unit stations will be considered to maintain flexibility.

5.4 *Site Acquisition*

5.4 New sites for major generating plant shall be sought to allow generating stations of economic size to be built while maintaining a geographical balance of electricity demand and supply.

5.5 *Existing Plant*

5.5.1 A high priority will be given to maintaining and improving the performance, efficiency and reliability of the existing generation and transmission facilities.

5.5.2 Rehabilitation or redevelopment of existing facilities should be assessed along with the other demand and supply options.

5.5.3 Rehabilitation or redevelopment of existing hydroelectric facilities will be favoured since this involves the continuing use of a renewable resource.

5.5.4 Programs will be implemented to assure the safe economic service lives of existing nuclear stations.

5.5.5 To provide a flexibility margin, consideration should be given to retaining in a preserved state existing plant that has reached the end of its useful life.

5.6 *Alternative Generation*

5.6.1 Ontario Hydro will continue to investigate the technical and economic feasibility of alternative generation sources, particularly those that use renewable and Ontario resources.

5.6.2 Ontario Hydro will implement alternative generation sources in specific situations (eg., isolated systems) where they are the most beneficial alternatives.

5.7 *Hydraulic*

5.7 Hydraulic developments should be undertaken in an orderly program where they are economic.

5.8 *Nuclear*

5.8 Ontario Hydro will seek to maintain CANDU nuclear so that it is available for future development.

5.9 *Fossil*

5.9.1 Ontario Hydro will maintain and improve its knowledge base of new developing coal burning technologies that promise reduced emissions and/or increased flexibility.

5.9.2 Gas and oil burning plant for peaking purposes will be considered to provide flexibility recognizing the short lead time and fast start capability that can be achieved.

6.0 Purchases

6.1 Ontario Hydro will continue to depend on neighbouring systems for emergency support and economy interchange to a level that is consistent with mutual benefit.

6.2 Long term firm purchases of hydraulic power from neighbouring provinces will be considered as an acceptable alternative to building new supply facilities after maximum efforts are made to utilize the cost effective indigenous resources of Ontario.

APPENDIX B

List of References for

Demand/Supply Plan Report

Chapter 1

1. "Meeting Future Energy Needs. An Initial Review of the Options." Report No. 651 SP, November 1985. Ontario Hydro, System Planning Division.

2. "Environmental Analysis Report" December, 1989 Ontario Hydro.

3. "Demand/Supply Options Study. The Options." Report No. 652 SP, February 1989. Ontario Hydro, System Planning Division.

4. Ontario Hydro Presentations to the Select Committee on Energy on the Demand/Supply Options Study. April 1986.

5. Recommendations of Select Committee on Energy. Final Report. July 1986.

6. Meeting Future Energy Needs – Provincial Organization Consultation Program: Volume 1, The Consultation Process; May 1986 Volume 2, Summary of Submissions; April 1986 Volume 3, Submissions by Organizations; May 1986. Ontario Hydro, Corporate Relations Division.

7. Meeting Future Energy Needs – Regional Consultation Program: August, 1986. Ontario Hydro, Corporate Relations Division.

8. Meeting Future Energy Needs – Regional Consultation Program; Questionnaire Results; August 1986. Ontario Hydro, Corporate Relations Division.

9. Meeting Future Energy Needs – Municipal Utility Consultation Program: December 1986. Ontario Hydro, Corporate Relations Division.

10. "Meeting Future Energy Needs. Draft Demand/Supply Planning Strategy." Report No. 666 SP, December 1987. Ontario Hydro, System Planning Division.

11. "Meeting Future Energy Needs. Draft Demand/Supply Planning Strategy." Supplementary Documents." Report No. 666A SP.

12. "Review of Ontario Hydro's Draft Planning Strategy." Report of the Electricity Planning Technical Advisory Panel to the Minister of Energy, July 1988.

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14. "Draft Demand/Supply Planning Strategy" (summary). Report No. 666B SP. September 1988. Ontario Hydro, System Planning Division.

15. Ontario Hydro Presentations to the Ontario Nuclear Cost Inquiry. November 1988.

16. "Ontario Nuclear Cost Inquiry." Report to the Minister of Energy. January 1989.

17. "Select Committee on Energy. Report on Ontario Hydro Draft Demand/Supply Planning Strategy." January 1989.

18. "Draft Demand/Supply Planning Strategy Review." Report No. 666C SP. April 1989. Ontario Hydro, System Planning Division.

19. "Demand/Supply Planning Strategy." Report No. 666D SP. March 1989. Ontario Hydro, System Planning Division.

Chapter 3

1. Load Forecast Report No. 881212. April 1989. Ontario Hydro Economics and Forecasts Division.

Chapter 7

1. "Independent Consultant Review of Ontario Hydro Expectations and Targets for Demand Management Activities." August 1989. RCG/Hagler Bailly Inc.

2. "Demand Management in the 1989 Demand/Supply Plan." December 1989. Ontario Hydro, System Planning Division.

Chapter 8

1. "The 1989 Non-Utility Generation Plan." August 1989. Ontario Hydro, Non-Utility Generation Division.

Chapter 12

1. "The Hydraulic Plan." December 1989 Ontario Hydro, System Planning Division.

Chapter 14

All references in Chapter 1 plus:

1. "The Safety of Ontario's Nuclear Power Reactors. A Scientific and Technical Review." February 1988. Report to the Minister from the Ontario Nuclear Safety Review Commission.

2. "Thermal Cost Review Report." November 1989. Ontario Hydro.

3. "Ontario Hydro Thermal Cost Review Assessment Report." August 1989. Monenco Consultants Inc.

Chapter 15

All references in Chapter 1 plus:

1. Demand/Supply Plan Analysis Report. Ontario Hydro, System Planning Division.

APPENDIX C

Glossary

annual capacity factor (ACF) – the average capacity factor in a specified year.

acquisition phase – the period from the decision to build to the in-service date.

avoided cost – supply costs which are avoided when any demand or supply option is substituted for an equivalent part of a demand/supply plan.

capacity factor – a measure of the use of a generating facility; expresses, as a percentage, how the actual energy produced by the facility compares with the energy it could have produced if operated continuously at full power.

$$\% \text{ capacity factor} = \frac{\text{Energy}}{\text{Capacity x Time in period}} \text{ x } 100$$

bandwith forecast – load forecast expressed as a band; an 80 % probability exists that future load will be within the band.

base load – a level of aggregate electricity demand that exists 70% of the time or more.

base load generation – a generating station expected to operate at 60% capacity factor or higher.

Basic Load Forecast – what the demand for electricity would be without Hydro's financial incentives to influence the level and timing of electricity demand.

Bulk Electricity System – the integrated system of transmission lines and stations by which electric power is delivered from major generating stations to and between load centers, and to and from interconnections with neighbouring utilities.

Capacity Interruptible Load – load which customers agree, on request, to curtail, in return for reduced rates; helps the utility deal with periods when system demand is about to exceed the utility's ability to supply that demand.

capacity margin – the reliability reserve expressed as a percentage of installed capacity.

cogeneration – the ability to generate electricity and heat, usually in the form of steam, at the same time.

CO_2 emissions – emission of carbon dioxide (CO_2) gas to the air from the burning of a fossil fuel.

commitment – the authorization to proceed with an option, i.e., build a generating station, sign a purchase agreement, implement a demand management program; other approvals may be required after commitment.

configuration – number of units per station, size of each unit, and the number and arrangement of major parts in a unit.

constant dollars – the estimated cost in a given year, adjusted to a base year, in this report, 1989; also known as real dollars; see Chapter 6.

conversion process – manner in which primary energy is converted into electrical energy.

creep – change over time in shape of metal due to stress, e.g., high pressure or temperature.

customer unsupplied energy – the amount of customer energy demand unsatisfied.

decommissioning – the act of taking a facility out of service permanently.

definition phase – the period from formulation of intent to proceed with the project to project commitment; includes planning specifications, obtaining approvals and preliminary engineering.

demand – the power and energy that must be generated to meet customer needs; includes delivery losses.

demand management – measures taken by Ontario Hydro and municipal utilities to influence the amount and timing of customer electricity demand.

direct and allocated costs – direct costs attributable to an option, plus an appropriate share of costs associated with that option.

direct load control – demand management program in which customer load is directly controllable by Ontario Hydro or the municipal utility.

dispatchability – Hydro's ability to vary the output of a generating unit.

electrical efficiency improvements (EEI) – the required output of goods and services is achieved with reduced amounts of electricity consumption.

EEI – Attainable Induced EEI – identified net reduction in power and energy expected to be induced as a result of Hydro Family incentive-driven EEI programs.

EEI – Attainable Total – total identified net reduction in power and energy expected as a result of Natural EEI and the Plan Induced EEI.

EEI – Natural – reduction in electric power and energy expected to occur due to normal market forces.

EEI – Potential Induced – identified net potential reduction in electrical power and energy, which is both technically and economically possible,and is induced by Hydro Family incentives.

EEI – Plan Induced – total net reduction in power and energy expected as a result of the Induced EEI program.

EEI – Penetration Rate – percentage of potential reduction that can be achieved for a specific demand option by a specific year, considering all practical limitations such as customer acceptance, barriers, actions to overcome barriers, infrastructure status and levels of incentives.

EEI – Potential Total – potential reduction in electrical power and energy, considering identified opportunities.

EEI – Unidentified – expected reduction in power and energy arising from new ideas and emerging technology; based on judgement.

electricity intensity – the amount of electrical energy consumed per constant dollar of real Gross Domestic Product; expressed in kilowatt hours per dollar (kWh/$).

energy – the amount of electricity supplied or used, expressed in watt hours or multiples thereof.

energy meeting capability – the energy a system can produce after allowing for factors such as generating outages, environmental restrictions and the time of day when electricity is used.

environmental control – concepts utilized to eliminate or mitigate emission effects arising from demand/supply options.

escalated dollars – estimated dollars of any given year.

Firm Load Forecast – the electric power and energy which Ontario Hydro must generate or purchase to meet all customer electricity demand, except capacity interruptible loads (CIL).

Flue Gas Desulphurization – process in which sulphur dioxide is removed from the flue gas of a fossil-fueled generating station; synonymous with scrubbers.

free riders-demand management – participants in demand management programs who take advantage of incentives and who would have implemented the improvements without the incentives.

generating capacity – the peak power output of generation, i.e., unit, station, system.

generation type – designation for options based on the primary fuel, e.g., fossil, nuclear, hydraulic.

giga – a billion; a gigawatt is a billion watts.

heavy water – deuterium oxide, D_2O, the moderator and heat transport fluid used in CANDU reactors.

inter-area transmission – one or more transmission circuits interconnecting areas of the Bulk Electricity System; transmits electricity from points of generation to poins of use; excludes radial transmission.

intermediate load – a level of aggregate electricity demand that exists 20 to 70% of the time.

intermediate load generation – a generation station expected to operate at 20 – 60% capacity factor.

kilo – a thousand; a kilowatt is a thousand watts.

lead time – the period from the planning decision to proceed with an option to the time in which the desired result is achieved, i.e., demand option achieves reduction, supply option goes into service.

levelized unit energy cost (LUEC) – a single value in constant dollars representative of the unit cost of energy, in cents per kWh, delivered by a station over its service life; utilizes the present value technique.

load – electricity (peak power and energy) consumed to meet customer electricity needs; synonymous with customer load.

load displacement (NUG) – supplies electricity to meet the producer's own needs, or is directly purchased by a customer other than Hydro.

load factor – for a given load consumption, the average power divided by peak power; expressed as percentage.

Load Meeting Capability (LMC) – the power demand which can be met after allowing for the reliability reserve.

load shifting (LS) – shifting electricity consumption from peak to off-peak periods.

lower forecast – the lower bound of the load forecast bandwith; there is a 10% chance that demand will be lower than this level of electricity demand (peak power and energy).

median forecast – the central tendancy of the load forecast bandwith; there is a 50% chance that demand will be lower than this level, and a 50% chance that it will be higher.

mega – a million; a megawatt is a million watts.

moderator – material used within the core of a nuclear reactor to slow down or moderate neutrons produced by fission of uranium; increases the likelihood of subsequent fission.

NO_x emission – residual emission of nitrogen oxides (NO_x) gas to air, with or without reduction measures, from the burning of a fossil fuel.

non-utility generation (NUG) – electrical generation in Ontario owned and operated by electricity producers other than Ontario Hydro; includes private and municipal utilities, and private power producers.

option – specifically defined way of meeting electricity requirements, e.g., a supply option is defined by primary energy, conversion process, configuration, environmental control and system application.

peak load (customer pattern) – a level of aggregate demand that exists 0 to 20% of the time.

peak load generation – a generating station expected to operate at a capacity factor of no more than 20%.

peak power demand – the maximum power demand within a given period.

power – the rate at which energy is supplied or used; expressed in this document in watts or multiples thereof.

present value – aggregate of expected expenditures and/or benefits during all relevant years, discounted to a specified year.

primary energy – energy forms available to Hydro which may be converted into electrical energy, e.g., coal, oil, gas, hydraulic, nuclear, solar, wind, etc.

Primary Energy Demand – the amount of electricity energy Ontario Hydro must generate or purchase to meet customer demands.

Primary Load Forecast – forecast of peak power and energy which Ontario Hydro must generate or purchase to meet the demand of its customers.

radial transmission – one or more transmission circuits connecting a generating station into the Bulk Electricity System; together with inter-area transmission, forms the transmission necessary to incorporate a new generation station into the Bulk Electricity System.

redevelopment – reuse of an existing site for a new generating facility; steps taken to make possible the use of an existing hydraulic resource beyond the expected life of the facility.

rehabilitation – major restoration or improvement of a generating unit's long-term performance to assure or extend its life expectancy, e.g., ensure compliance with new safety or environmental requirements, replace inefficient or technically and/or economically obsolete equipment.

reliability reserve – the capacity required to ensure reliability, allowing for outages, derating, uncertainties in load growth, late in-service dates, etc.

reserve margin – reliability reserve capacity expressed as a percentage of firm peak power demand.

resource – something that can be drawn on to meet a need; in this plan, has particular meaning with respect to primary energy resources such as hydraulic, uranium, oil, natural gas, solar, wind.

run-of-the-river station – hydraulic station using water at the rate naturally supplied by a river; little or no capacity to store water.

scrubbers – see FGD.

Selective Catalytic Reduction (SCR) – a process in which nitrogen oxides are removed from the flue gas of a fossil-fueled generating station.

single-circuit line – a transmission line with one three-phase circuit; a set of three conductors.

SO_2 emission – residual emission of sulphur dioxide (SO_2) gas to the air, with or without sulphur reduction measures, from the burning of fossil fuel.

source – where something comes from; someone who supplies something, e.g., coal from United States, motor from West Germany; the point of emission, e.g., sulphur dioxide from Lakeview Generating Station.

system application – role served by a supply option, i.e., peak load, intermediate load, base load.

system expansion cost – estimated incremental expenditures for facility additions.

technical potential (EEI) – theoretical reduction in electricity demand, if all current technology improvements were made throughout the province without regard for cost or people's preferences, e.g., replacing all electrically heated homes with R2000 homes; impractical calculation, not used by Hydro.

tera – a trillion; a terawatt is a trillion watts.

time-of-use rates (TOU) – the application of lower rates during night time, weekends, holidays and summer; the application of higher rates during day-time, work days and winter; TOU rates induce demand management load shifting.

Total Customer Cost – all costs of providing a customer's electricity needs, e.g., artificial light and home heating; includes the costs of producing, transmitting and distributing the electricity; and the costs incurred by the end user in obtaining the required service, e.g., wiring, insulation, appliances.

upper forecast – the upper bound of the load forecast bandwith; there is a 10% chance that electrical demand will exceed this level.

watt – a measure of electrical power, i.e., a 100-watt lightbulb.

watt hour (Wh) – a measure of electrical energy; equal to power (watts) multiplied by time (hours), i.e., a 100-watt lightbulb operating for 10 hours requires 1000 watt hours.

Commonly Used Acronyms

ACF – Annual Capacity Factor

AFBC – Atmospheric Fluidized Bed Combustion

AUEC – Accounting Unit Energy Cost

BES – Bulk Electricity System

CANDU – CANadian Deuterium Uranium

CC – Combined Cycle

CO_2 – Carbon Dioxide

CSC – Conventional Steam Cycle

CPI – Consumer Price Index

CIL – Capacity Interruptible Load

CTU – Combustion Turbine Unit

CTU/G – Combustion Turbine Unit General

CTU/CC – Combustion Turbine Unit convertible to Combined Cycle operation

CTU/IGCC – Combustion Turbine Unit convertible to Combined Cycle and Integrated Gasification Combined Cycle operation

CTU/NC – Combustion Turbine Unit Non Convertible

DM – Demand Management

D/SPS – Demand/Supply Planning Strategy

EA – Environmental Assessment

EEI – Electrical Efficiency Improvement

FGD – Flue Gas Desulphurization

GDP – Gross Domestic Product

IGCC – Integrated Gasification Combined Cycle

LD-NUG – Load Displacement Non-Utility Generation

LF – Load Factor

LMC – Load Meeting Capability

LS – Load Shifting

LUEC – Levelized Unit Energy Cost

NO_x – Nitrogen Oxides

NUG – Non-Utility Generator/Non-Utility Generation

OM&A – Operation, Maintenance and Administration

ONCI – Ontario Nuclear Cost Inquiry

P-NUG – Purchase Non-Utility Generation

SCR – Selective Catalytic Reduction

SO_2 – Sulphur Dioxide

TCR – Thermal Cost Review